PROGRAM

THE SEVENTH CERI
INTERNATIONAL OIL AND GAS MARKETS CONFERENCE

Sponsored by the
Canadian Energy Research Institute

in collaboration with
The Calgary Chamber of Commerce

September 18-20, 1988

91-02926/

THE SEVENTH CERI
INTERNATIONAL OIL AND GAS MARKETS CONFERENCE

September 18-20, 1988
Calgary Convention Centre

SUNDAY, SEPTEMBER 18

7:00 p.m. - 10:00 p.m. — Registration and Reception
Garden Terrace

MONDAY, SEPTEMBER 19

7:30 a.m. — Registration - Macleod Hall A

8:30 a.m. — Welcome - Conference Chairman
Dr. Gerry Angevine
Executive Director
Canadian Energy Research Institute
Calgary, Alberta

8:40 a.m.

KEYNOTE ADDRESS ON THE STATE OF THE WORLD OIL MARKET

(not available) Dr. Herman Franssen
Economic Advisor to The Minister
of Petroleum and Minerals
Muscat, Sultanate of Oman

WORLD OIL MARKET PERSPECTIVES

Chairperson:
Mr. Bijan Mossavar-Rahmani
President
Apache International Inc.
Denver, Colorado, and
Chairman
Associates of the Harvard International
Energy Program

Mr. Charles Maxwell
Vice Chairman and Senior Energy Strategist
C. J. Lawrence, Morgan Grenfell Inc.
New York, New York

10:15 a.m. — Coffee Reception

Mr. Robert Reed III
Chairman, President and C.E.O.
Pacific Resources, Inc.
Honolulu, Hawaii

Dr. C. S. Gibson-Smith
Manager, Corporate and Energy
Analysis Division
BP International Limited
London, England

12:00 noon — **Luncheon**
"U.S. Regulatory Changes in Oil and Gas and Their Impact on Canadian Exports"

Mr. Chandler L. van Orman
Deputy Administrator
Economic Regulatory Administration
U.S. Department of Energy
Washington, D.C.

2:00 p.m.

INTERNATIONAL GAS TRADE DEVELOPMENTS

Chairperson:
Mr. Doug Fenton
President
Alberta and Southern Gas Co. Ltd.
Calgary, Alberta

Europe
Dr. Gerhard Enseling
Senior Vice-President
Ruhrgas AG
Essen, Federal Republic of Germany

North America
Dr. Dan Dreyfus
Vice President, Strategic Analysis and
Energy Forecasting
Gas Research Institute
Washington, D.C.

3:15 p.m. — **Coffee Reception**

3:45 p.m.

ENHANCED OIL RECOVERY OUTLOOK

Chairperson:
Mr. Norm Strom
Vice Chairman
Energy Resources Conservation Board
Calgary, Alberta

Canada
Mr. J. Sherrold Moore
Senior Vice President Production
Amoco Canada Petroleum Company Ltd.
Calgary, Alberta

United States
Mr. Tom Burns
Manager, Economics
Corporate Planning and Analysis
Chevron Corporation
San Francisco, California

North Sea
Mr. Peter Parris
Managing Director
Winfrith Petroleum Technology
Dorchester, England

5:00 p.m. — Reception - Garden Terrace

7:00 p.m. - 9:30 p.m. — **Dinner - Macleod Hall A**
"Prospects for Oil Exploration Activity Worldwide"

Mr. Clarence Cazalot, Jr.
General Manager, Frontier
Exploration Department
Texaco Inc.
Bellaire, Texas

TUESDAY, SEPTEMBER 20

8:30 A.M.

GAS MARKET CHALLENGES - UNITED STATES

Chairperson:
Dr. Fred Button
Vice President, Market Planning and Development
Western Gas Marketing Limited
Calgary, Alberta

California
Mr. Robert Loch
President
Pacific Interstate Transmission Company
Los Angeles, California

Northeastern States
Mr. Robert Catell
Executive Vice President & Chief
Operating Officer
Brooklyn Union Gas Company
Brooklyn, New York

Midwestern States
Mr. Richard Terry
President
People's Gas Light and Coke Company
Chicago, Illinois

9:45 a.m. Coffee Reception

10:15 a.m.

GAS MARKET CHALLENGES - CANADA

Chairperson:
Mr. Joe Horler
Vice President, Marketing
Oil and Gas Division
BP Resources Canada Limited
Calgary, Alberta

Alberta
Mr. Larry Graburn
Executive Vice President, Resources
Canadian Western Natural Gas Company Limited,
Northwestern Utilities Limited and CU Gas
Calgary, Alberta

British Columbia
Mr. Art Willms
Executive Vice President and
Chief Operating Officer
Westcoast Energy Inc.
Vancouver, B.C.

Ontario
Mr. Norm Loberg
Vice President Marketing
Consumers Gas Company Ltd.
Toronto, Ontario

12:00 noon — Luncheon
"Oil Exploration and Development in the Third World"

Dr. Anthony Churchill
Director, Industry and Energy Department
World Bank
Washington, D.C.

2:00 p.m.

OIL AND GAS POLICY AND PROSPECTS TO 2005

Chairperson:
Mr. Ron Erdmann
Director General
Financial and Market Analysis Branch
Energy, Mines and Resources Canada
Ottawa, Ontario

Norway
Mr. Odd Haraldsen
Assistant Director General
Royal Ministry of Petroleum and Energy
Oslo, Norway

Brazil
Dr. Milton Romeu Franke
General Manager of Exploration
PETROBRAS (Petroleo Brasileiro S.A.)
Rio de Janeiro, Brazil

Canada
Mr. Anthony Reinsch
Vice President
Canadian Energy Research Institute
Calgary, Alberta

Papua New Guinea
Mr. Gary Robinson
Assistant Secretary (Policy)
Department of Minerals and Energy
Konedobu, Papua New Guinea

Not Available

People's Republic of China
Mr. Zhou Fengqi
Director
China Energy Research Institute
State Planning Commission
Beijing, People's Republic of China

United States
Ms. Margaret Sibley
Acting Director
Office of Policy, Planning and Analysis
U.S. Department of Energy
Washington, D.C.

(Coffee will be available at the back of the hall during this session)

5:00 p.m. Reception

Presentation by

Charles T. Maxwell
Vice Chairman and Senior Energy Strategist
C.J. Lawrence, Morgan Grenfell Inc., New York

Seventh CERI International
Oil and Gas Markets Conference
Calgary, Alberta, Canada

September 18-20, 1988

CERI INTERNATIONAL OIL AND GAS MARKETS CONFERENCE
September 19, 1988

Charles T. Maxwell
Vice Chairman and Senior Energy Strategist
C.J. Lawrence, Morgan Grenfell Inc.

The oil and gas industry isn't so much "changing" as it is going back to the kind of operation it traditionally has been--a fiercely competitive commodity business, generally with oil and gas in oversupply over the past 100 years.

The shortfall in investment required to maintain oil and gas reserves is much more marked in the U.S.A. and Canada than it is abroad. Certainly, the global surplus of producibility will eventually come down, but probably at a slower rate than has been generally forecast. Further, slower world GNP growth, continued conservation efforts, breakthroughs in energy-finding and processing technologies, and the consistent development of competing fuels will all work to keep oil and gas prices at lower levels for a longer time than has been accepted up to now by the consensus of oil industry managers.

The oil and gas business was helped in the 1960s and 1970s by the effects of gathering world inflation, artificially-stimulated growth, and by greater government intervention which, whatever its original objective, worked to support prices. These three props have been removed. Planners now must work on "base case" and "worst case" scenarios to protect themselves.

Lastly, the future cohesion of OPEC remains a vexed issue. If the recently arranged cease-fire in the Gulf War holds, and if this were followed by a successful peace conference in late 1988 or early 1989 (favorable odds of two out of three, on our reckoning), then, in terms of oil pricing, there would be a real opportunity to heal the rift between Arab and Iranian-led wings in OPEC, bring Iraq back into the oil production quota system as part of the peace agreement, and settle Kuwait, Qatar and Abu Dhabi (at 1.1 million barrels per day, apart from Dubai) back into their quotas for the first time in two or three years.

All of the above could happen, but it certainly is not yet determined. The potential spoiler, as we see it, would be a sharp decline in oil prices in the late summer and early autumn that could, if allowed to run unchecked, foreclose some of the options that we have calculated might bolster OPEC's position next year.

The short-term wrecking scenario would run this way. Supply and demand in the summer of 1988 are not in balance. OPEC is currently believed to be producing volumes in the 18.8-19.0 million barrels per day range into a Free World market that we calculate can absorb no more than 17.5-18.0 million barrels on a daily consumption basis. If all members were at their "expected" quota levels, OPEC output would theoretically reach 17.5 million barrels per day, but both Iraq and the United Arab Emirates (Abu Dhabi) are well exceeding their numbers and are plainly stating their intention to continue this practice. World crude inventories have been rising above normal seasonal

expectations since May, and have now reached levels indicating increasing risk of a price break unless overproduction can be curbed. Further, there are some six weeks of June/July OPEC production at close to 19 million barrels per day that is on the water travelling to market, even if members do produce a bit less oil in August. In addition, if a cease-fire in the Gulf is achieved this month, as we consider likely, Iranian production immediately could rise by 200,000-300,000 barrels per day, as the threat of Iraqi air attacks recedes and Iran is once again able to produce its full OPEC quota (2.37 million barrels per day, but output could float over this mark for purposes of averaging). Lastly, Iraq may not feel any compunction about producing every oil barrel it can prior to the limitation of oil production it will likely have to accept as part of an eventual peace settlement.

The final point above is surely the critical one, and it merits further explanation. If the cease-fire is implemented, and is confirmed by a few weeks of full observance, the Iraqis could gain enough confidence to move one or two of their four available 200,000 barrels per day single-point mooring systems out of storage at Bahrain and place it (or them) close to Fao. This would allow Iraq to start exporting crude from the Basrah area within a few months. Such an action by itself would likely frighten the oil markets with its implication of uncurtailed output rises ahead--at least to the point in time when a peace agreement is finally hammered out. Still, how certain is that event, and how many months away could it be?

In short, the near-term situation is fraught with peril to the price of oil. At best, crude may stay in the lower half of the $14-$18 per barrel range created over the last 18 months. At worst, prices could fall to the $10-$12 per barrel range for a short period. After that, OPEC would probably rouse itself, limit production, and bring prices back to at least the mid-point of the previous range. However, as events such as these unfold, who can define their limits at the time?

CHARLES T. MAXWELL

POWERING THE PACIFIC
PAST, PRESENT AND FUTURE

Presented by
Robert G. Reed III
Chairman, President and Chief Executive Officer
Pacific Resources, Inc.
Honolulu, Hawaii
USA

At
The Seventh Annual CERI
International Oil and Gas Markets Conference
September 18-20, 1988
Convention Centre
Calgary, Alberta

POWERING THE PACIFIC
PAST, PRESENT, AND FUTURE
SYNOPSIS

Presented by

Robert G. Reed III

Chairman, President and Chief Executive Officer

Pacific Resources, Inc.

Honolulu, Hawaii

USA

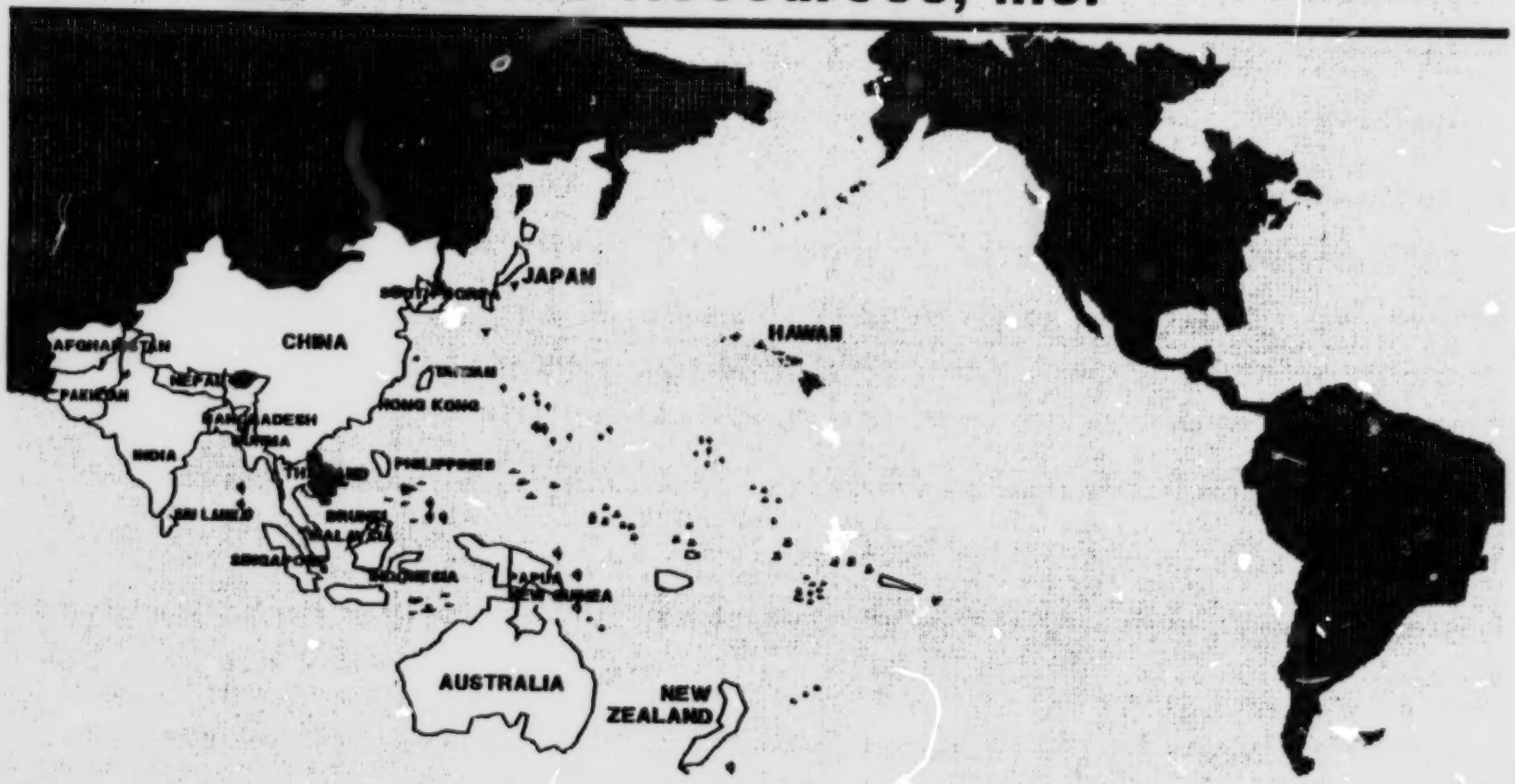
With a high concentration of growing and industrializing countries, the Asia-Pacific region has triggered petroleum industry anticipation of significant growth opportunities. The region provides substantial opportunities for those willing to adapt to its dynamic, everchanging environment.

REGIONAL HISTORY AND POLITICS

The Asia-Pacific region consists of over twenty independent countries. (See map, includes China, Hong Kong, South Korea, Indonesia, Malaysia, Philippines, Singapore, Taiwan, Thailand, New Zealand, Australia, Japan, Brunei, Papua New Guinea, Afghanistan, Bangladesh, Burma, India, Nepal, Pakistan, Sri Lanka, and the South West Pacific Islands.)

From modern industry beginnings in the 1800s, the major international oil companies performed a broker function for the region, purchasing crude from the Middle East and utilizing their established distribution networks to supply the many small customers. In addition to Middle East purchases, the majors developed regional reserves and refining.

Pacific Resources, Inc.



Change came with removal of the oil company middlemen. Rather than dealing with a handful of "full-service" companies, each country is now faced with an almost infinite number of options.

In response to the complexities inherent in petroleum management, just about every country has regulated facets of the industry. Though the regulations appear to change frequently, each country's goal is to achieve the degree of control necessary to provide internal stability.

For example; Japan, Australia, and New Zealand have historically maintained control over some petroleum pricing and distribution. In keeping with a constantly changing environment, all three have announced liberalization or deregulation plans in the past year.

The higher growth, newly developed and developing countries have generally maintained control over key sectors of the petroleum business. Governments in Korea, Taiwan, China, Indonesia, and the Philippines regulate all aspects of the industry.

Countries like Malaysia moderate the strict controls taken by other governments by setting only a maximum wholesale price. In addition, the government has minor controls on crude production and licenses upstream foreign investment.

Finally, Singapore maintains the least regulated petroleum sector in the region. Though the Ministry of Industry sets maximum wholesale prices, all other aspects of the industry are market driven.

The future of any single country will vary with regional developments and governmental policies. However, the region as a whole holds promise.

REGIONAL GROWTH

Since 1978, while OECD oil consumption fell an average of 1.6% annually, Asia-Pacific regional consumption rose by 0.5%. Indeed, if Japan is removed from the statistic, regional growth averaged 2.7% annually.

For these countries, economic growth in the 1980s has consistently outperformed the rest of the world. (Graph: Real GNP/GDP Growth) In 1987, Asia-Pacific regional output grew 2% faster than the world as a whole. While the countries' internal markets cannot support substantial GNP growth, access to the consumer-rich developed countries allows expansion.

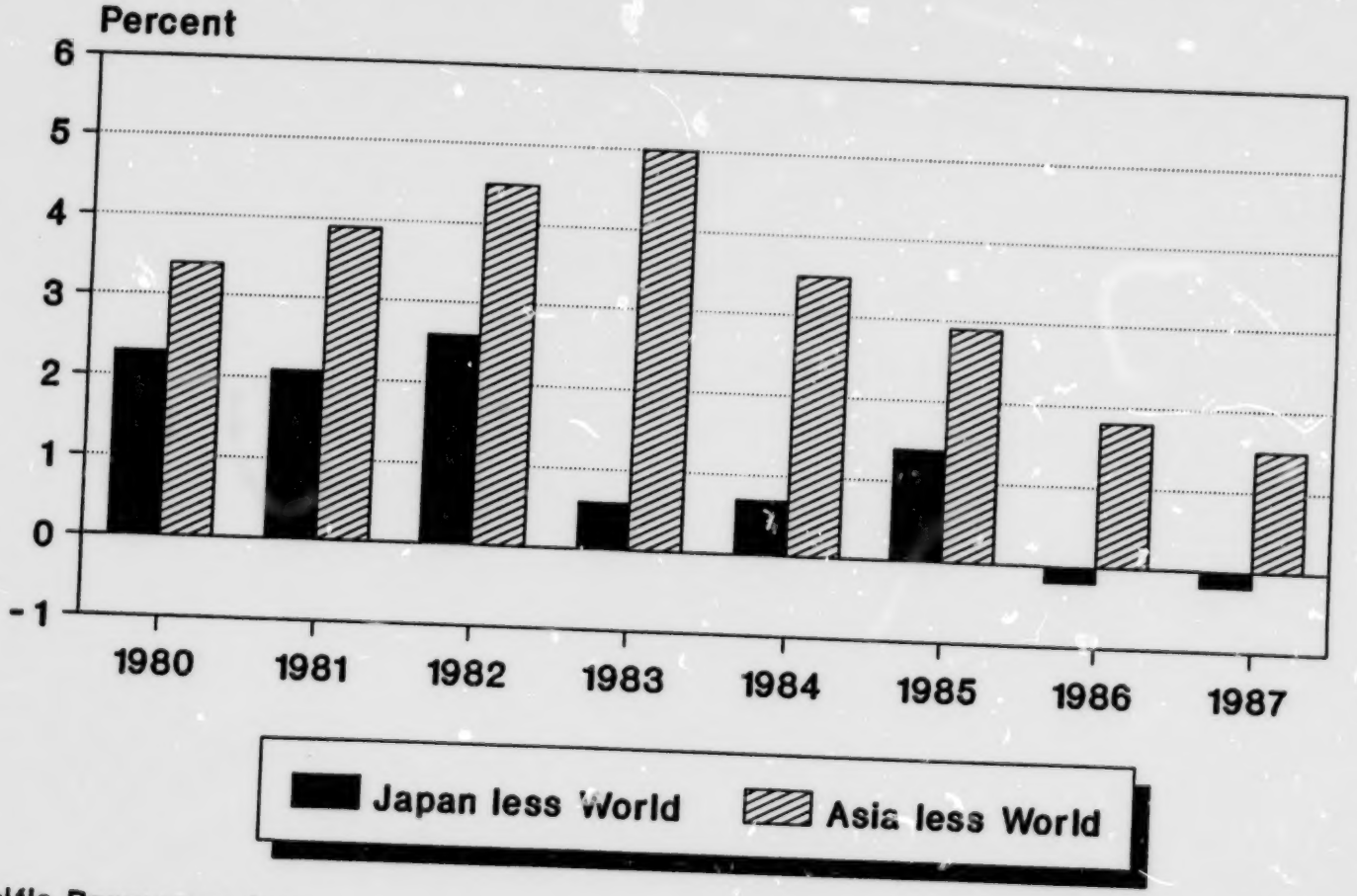
In 1987, Asia-Pacific oil consumption grew 3% faster than the world as a whole. Asia-Pacific regional oil consumption, including Japan, reached 18% of world demand. Japan alone accounts for about 7% of the total. However, while Japan's share of world consumption has declined from over 9% in the early 1970s, the rest of the region has more than doubled its share over the last two decades. (Graph: Asia-Pacific Consumption)

Absolute demand growth has been accompanied with a strong shift in products demanded. Middle distillate demand has grown consistently since the late 1970s while demand for fuel oil has risen only slightly. In 1987, middle distillate demand grew by over 9% from 1986 while residual fuel demand grew by just over 2%.

The ratio of cracking to distillation in the Asia-Pacific region is about 15 percent, compared to 53 percent in the U.S. and 31 percent in Canada and Mexico. The deficiency in cracking capability severely restricts refiners' ability to turn residual fuel oil into middle distillates and light products when demand for these products is growing.

Production and consumption comparisons illustrate the substantial gap filled by imports. (Graph: Asia-Pacific Import Dependence) With 11% of worldwide requirements, 5% of crude production and 4% of the world's reserves, the Asia-Pacific countries' dependence on imported oil can only increase over time.

REAL GNP/GDP GROWTH
Compared with World Growth Rate



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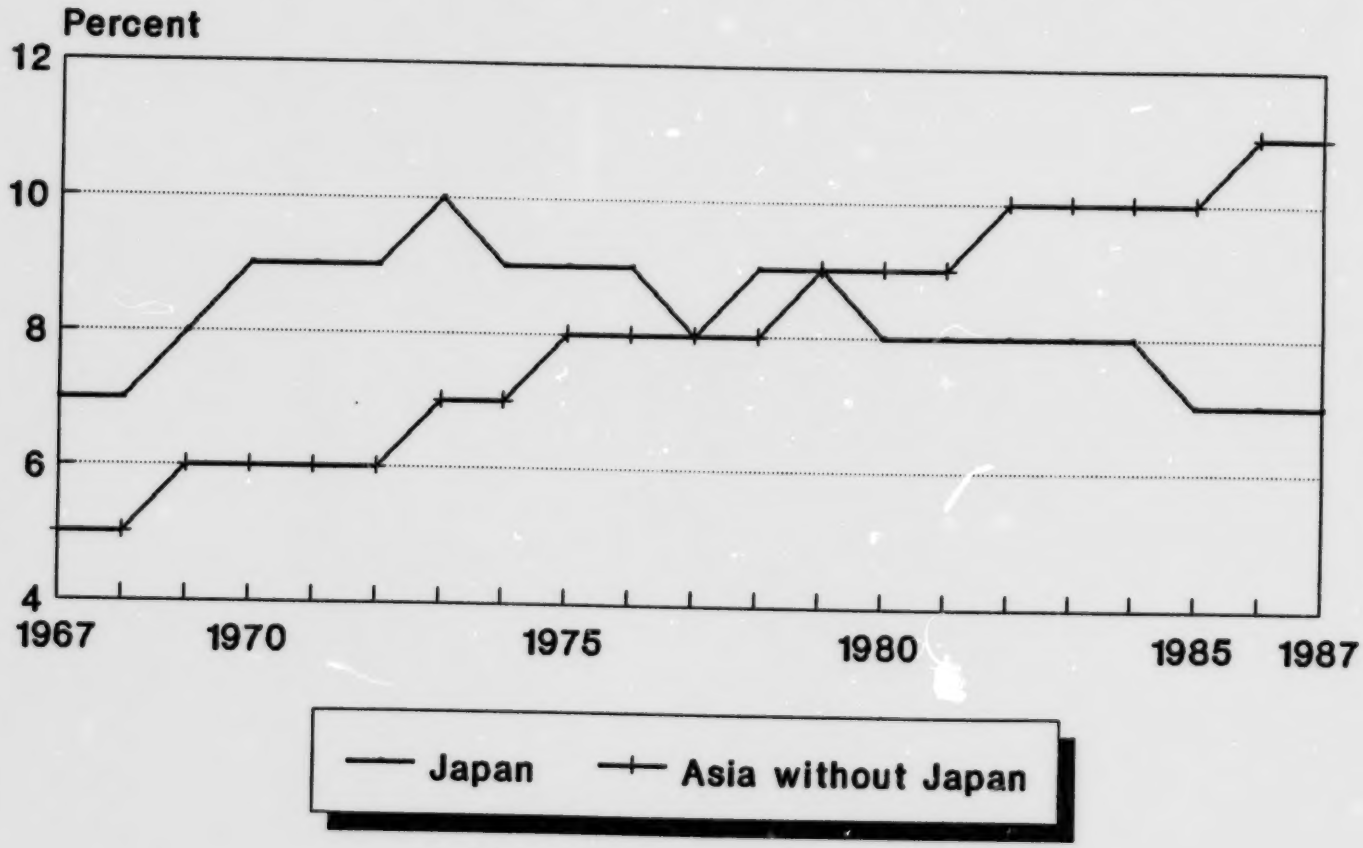
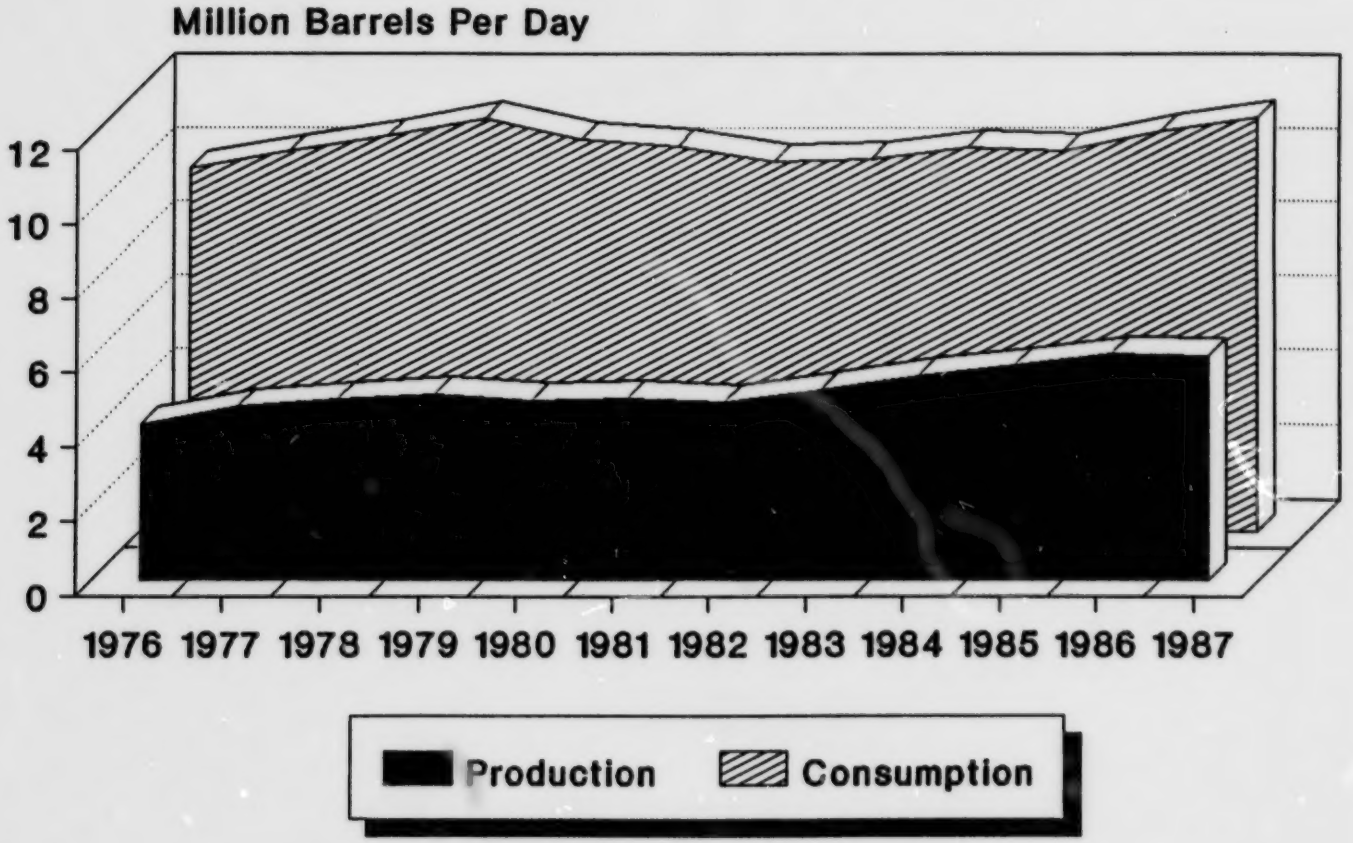
ASIA-PACIFIC CONSUMPTION

Percent of World Consumption



ASIA-PACIFIC IMPORT DEPENDENCE

Regional Production and Consumption



REGIONAL DEPENDENCE

By the year 2000, regional dependency on imported oil is expected to reach 85-90%. This would make the region one of the most import-dependent in the world.

As a result, while regional growth in petroleum consumption has outpaced the rest of the world, oil's share of total energy requirements in the Asia-Pacific region has declined.

Developing countries on average rely on oil for 50% of their energy needs, the Asia-Pacific countries use oil for 33% of requirements. Over the last ten years, oil's share of Asia-Pacific energy requirements has fallen by 10%. The lost share has been gained by gas, hydroelectric, and nuclear power in equal measure.

ENERGY ALTERNATIVES

By the year 2000, nuclear power should account for 11% of Asia-Pacific regional energy needs. Most of the gain will come at the expense of oil.

For the past ten years, coal has satisfied 51% of regional energy demand. However, coal must be considered a mature fuel with potential for expansion somewhat limited. Coal competes most directly with oil for market share. The relatively unsophisticated refinery business in the region produces an excess of fuel oil, keeping downward pressure on the price of fuel oil and, therefore, coal.

At current production rates, Asia-Pacific gas reserves will last 58 years, essentially the global reserve-to-production ratio. However, it is worth reiterating that, due to the accidental nature of gas discoveries, reserve figures may be understated. As a result, it is highly likely that the supply and demand picture for gas will change substantially over the next decade.

CONCLUSION

The Asia-Pacific region contains a great diversity of governments and cultures. However, economic and energy consumption growth well above the world average justifies taking the time to understand enough of the differences to operate within the region.

PRI has been active in the Asia-Pacific region for 15 years as an independent refiner/marketer/trader, currently operating out of Hawaii, Singapore, Sydney, Los Angeles and Houston. We've had to remain innovative and flexible to continue to grow in such a rapidly changing market.

Identifying the niche opportunities available in the Asia-Pacific region requires the independent refiner/marketer to be market responsive. The company must be open to new ideas and adjust to the extreme volatility now characteristic of the crude and product markets.

The short to medium term outlook for the Asia-Pacific region reflects continued strong growth. The challenge is to create an organization flexible enough to operate in a constantly changing environment. The ability to function effectively while working with a variety of governments and cultures is essential.

The Asia-Pacific region contains 17% of world refining capacity. Over one-fourth of the world volume of crude and product imports and about one-tenth of exports flow through the region. With 11% of the world's energy requirements, and growth holding 2-4% above the global rate, the Asia-Pacific nations comprise one of the few exciting opportunities left in the industry.

THE SHORT AND MEDIUM TERM OIL MARKET: A EUROPEAN PERSPECTIVE

Abstract
of presentation at the

Seventh CERI International
Oil and Gas Markets Conference
Calgary, Alberta, Canada

September 18-20, 1988

by

Dr. C. Gibson-Smith
Manager, Corporate Energy and Analysis Division
BP International Limited, London

THE SHORT AND MEDIUM TERM OIL MARKET: A EUROPEAN PERSPECTIVE

In the oil market, institutional and structural factors have captured the headlines over much of its history; from the Seven Sisters in the 1950's and 60's, to the emergence of OPEC in the 1970's. However, the fundamentals of oil demand and supply are no less important, and should be set in the context of the wider market for energy. In some applications, such as transport, substitutes for conventional oil are very expensive; in others, such as steam raising, there are many substitutes which have replaced oil. The supply of oil outside of OPEC has exceeded even the most optimistic forecasts of the early 1970's. Efficiency, technology, economic structure and consumers' behavior also adjusted to take up alternatives to expensive OPEC oil. But there were long adjustment lags.

The adjustment to higher prices that has taken place in Western Europe has been very significant. In 1973, Europe relied on oil for 60% of its energy needs; in 1987 this was reduced to 45%. In 1987, oil consumption was 12.3 mbd, still 2.6 mbd less than its peak in 1973. European oil production in 1987 was 4.2 mbd, mainly from the North Sea, compared with less than half a million barrels per day in 1973. Dependence on oil imports therefore declined significantly.

As a consequence of these and similar changes in demand and supply elsewhere in the world, there has been a global energy over supply for the past three years. The key questions for the oil market are when will the supply of alternatives to OPEC oil ebb, and what is the robustness of the growth of those key markets it retains. If these do not turn out favorable, will oil be able to price itself into those markets it has lost?

In Europe, the outlook for North Sea oil production, the protection of domestic coal industries and the role of gas in energy markets are the most important factors. On the demand side, environmental legislation, domestic pricing and economic growth will be the driving forces.

North Sea production, which grew from zero in the early 1970's to more than 3.7 mbd today is of particular relevance. UK production in the North Sea has now peaked at around 2.6 mbd. The prospects of major new discoveries are remote, but reserves growth from existing fields will continue to exceed previous expectations. For several months in 1988, the shut in of the Flotta blend, following the Piper Alpha disaster, could reduce production by up to 300,000 bpd. However, only 120,000 bpd will be lastingly affected. This can be overlayed on the gradual tailoff in production expected in the UK sector, perhaps of the order of 100,000 bpd each year. By contrast, Norway's production could increase to at least 1.4 mbd by the early 1990's, from current levels of 1.1 mbd. This would offset the decline in the UK sector.

Under almost all circumstances, OPEC excess production capacity will not easily be absorbed over the next five years. OPEC's willingness and ability to restrain output thus continues to be the critical factor determining oil prices over the short to medium term. The unfolding of the supply/demand balance is a key influence on the magnitude of the task ahead. So too are the increasing financial requirements of producing countries, and their internal and external politics. In these circumstances prediction inspires little confidence in businessmen. In BP, the scenario approach has proved a valuable tool for coping with the magnitude of uncertainty inherent in the oil market today.

U.S. REGULATORY CHANGES IN OIL AND GAS AND THEIR IMPACT ON CANADIAN IMPORTS

Presented by
Chandler L. van Orman
Deputy Administrator
Economic Regulatory Administration
U.S. Department of Energy
Washington, D.C.
United States of America

At
CERI International Oil and Gas Markets Conference
September 18-20, 1988
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For the next few minutes, I'm going to outline our National energy policy and energy trade policy. Then I'll discuss briefly a few of the Reagan Administration's actions taken the past 7-1/2 years in attempting to implement this policy - particularly those actions that affect U.S. - Canadian oil and gas trade. My concluding remarks will address what kind of legacy the Reagan Administration will leave to its successor.

1. U.S. NATIONAL ENERGY POLICY AND ITS IMPLICATIONS FOR IMPORTS

Our national energy policy goal is quite simple and straightforward. We want to obtain a sufficient supply of energy at a reasonable cost.

Although our policy goal is not unlike that of previous administrations, our strategies for attempting to achieve this goal are significantly different.

We have adopted two basic strategies for reaching this goal:

1. The first strategy is to minimize federal control and intervention in energy markets.
2. The second strategy is to seek a balanced and mixed energy resource system.

The Administration's objective with respect to oil and gas imports is to assure that a supply of energy, supplemental to domestic production, is available to the American consumer at competitive prices, while avoiding undue dependence on unreliable sources of supply.

Historically, Canada has proven to be a very dependable source of energy to the U.S. Thus, Canadian oil and gas supplies that are competitively priced are consistent with our overall strategy of achieving a balanced and mixed energy resource base.

11. FOCUS OF THE REAGAN ADMINISTRATION'S ENERGY POLICY

There has been a large and positive change in the U.S. energy industry in the 1980's. We have seen a great increase in competition based on market conditions. One key element in fostering competition has been the reduction in government intervention and regulation in both the U.S. and Canada.

In the U.S., President Reagan set the stage for a market-based approach to energy policy in his January 1981 directive to remove price and allocation controls on crude oil and petroleum products.

The ERA, formerly responsible for administering the oil regulations, has gone from approximately 2000 employees in 1980 to about 175 today. I might add that the majority of ERA's current employees are involved in winding down the litigation that still persists over the oil price and allocation regulations that were in place between 1973 and 1981.

In December 1983, Reagan rescinded the requirement that oil imports be licensed. This action eliminated another unnecessary regulation.

This administration recognizes that the U.S., during the foreseeable future, will be dependent on energy imports, probably increasingly so during the 1990's. Therefore, we have actively encouraged energy companies to purchase their imported supplies of petroleum from more secure and reliable countries, such as Canada and Mexico.

This policy has resulted in the U.S. becoming substantially less dependent on OPEC oil. Another result of this policy is the almost doubling of Canadian imports of crude oil and petroleum products since 1981. For the first six months of 1988, the U.S. imported about 987 thousand barrels of petroleum per day from Canada. If this trend continues for the remainder of the year, it will represent the largest volume of Canadian petroleum imports since 1974.

The recent repeal of the windfall profits tax gave a great psychological boast to the energy industry. Although the effect of this action is more symbolic than real at this time, it should give impetus to future exploration and development activities. At least Damocles sword has been removed from the oil industry.

As you can see, the Reagan administration has made substantial progress in eliminating federal regulations pertaining to oil. However, the task has been much more difficult in the natural gas industry. Unfortunately, the U.S. has not had as much success as Canada in this regard. Fifty years

of extensive regulation and a complex industry infrastructure made our task all the more formidable.

Despite our difficulties, we've had some major accomplishments. I'll focus on those that have a direct bearing on U.S.-Canadian trade.

A. ERA POLICY GUIDELINES

The DOE followed the President's initiative to decontrol oil and began a thorough review of its gas import policy in 1983. Three conclusions were reached:

- A flexible approach to pricing and import contracts was needed.
- Prices should be set through the market rather than through regulation.
- The government should establish a simplified review process for imports and exports.

Based on these findings, the Secretary of Energy issued new guidelines for natural gas imports and exports in February 1984. The guidelines were designed to encourage a more competitive atmosphere within which buyers and sellers could come together, unencumbered by excessive government regulation, to determine the terms of natural gas contracts. This action was intended to coincide with the partial decontrol of domestic wellhead prices under the Natural Gas Policy Act (NGPA) on January 1, 1985.

ERA employs three criteria in reviewing import applications: competitiveness, need for the gas, and security of supply. Thus a broader test of competitiveness has replaced the intense regulatory review process that previously existed.

Today's Canadian gas contracts have been crafted to respond to the changing requirements of the U.S. market. Canadian gas competes actively for both long-term and spot market sales.

(See Appendix A) The map in Appendix A shows the price range for Canadian gas, on a million Btu basis, at the various points of entry for both long-term and spot sales arrangements during the month of June. As one can readily see, the prices are very different from the uniform border

price of $4.94 of a few years ago. The weighted average price of natural gas exported from Canada to the U.S. under long-term arrangements during June for those companies filing sales reports with us was $2.10 per MMBtu.

The high per unit prices for long-term sales at several of the entry points are indicative of long-standing contract problems with a couple of import arrangements. Lower take levels have resulted in higher unit prices.

As shown in Appendix A, the prices for spot sales are generally reflective of the distance between the source of production and the markets, with the highest prices, for example, shown at Niagara Falls. The weighted average price of natural gas exported from Canada to the U.S. under spot market arrangements during June was $1.22 per MMBtu.

B. OPEN-ACCESS PIPELINES

The FERC, following the Administration's urging, established voluntary programs for open-access transportation by interstate pipelines at flexible, non-discriminatory rates.

Open-access to transportation and markets is essential for the establishment of a fully competitive natural gas market. It allows buyers access to more producers, and producers access to prospective buyers. These are indispensable ingredients in promoting a fully competitive marketplace.

The map in Appendix B illustrates the number of major interstate pipelines that have gone open-access, as of September 7. I think the few interstate pipelines that are not yet open-access will become so soon.

By the end of 1987, more than half of all gas delivered to market was transported by interstate pipelines for distributors, end users, marketers, and brokers. As recently as 1982, this portion had been only three percent. Open-access transportation by many of the major interstate pipelines has directly benefited Canadian gas exporters in spot market sales.

C. BLANKET AUTHORIZATIONS

To ease Canadian access to the spot market, ERA began granting blanket import and export authorizations in 1985.

These authorizations allow gas importers and exporters to freely negotiate individual spot and short-term sales for up to a two-year period without needing to obtain regulatory approval in advance of each transaction. These authorizations have also spurred Canada's participation in the spot market. As a result, spot gas imports from Canada now represent 25 percent of all Canadian sales to the U.S. during the past twelve months.

The pie chart in Appendix C shows the geographical distribution of Canadian spot sales from April through June 1988. Blanket authorizations, coupled with improved access to transportation, have fostered a wider distribution of Canadian gas. Spot market sales were made to 23 different states during this period.

D. FUEL USE ACT

The 1978 Fuel Use Act forced industries and electric utilities to burn coal instead of gas or oil. Congress repealed this law in 1987 because of its obsolescence in light of the 1980's natural gas surplus and the resulting decline in natural gas prices. It is our hope that lifting this control will increase demand for natural gas, thereby benefiting both producers (who could sell to a greater market) and consumers (who have a greater choice for their energy supplies).

III. LEGACY OF THE REAGAN ADMINISTRATION

The Reagan administration came into office determined to reduce government intervention and to encourage market-oriented competition. While complete deregulation in the natural gas industry has not yet been achieved, much has been accomplished, and we are working constantly at ways to relieve the market of unnecessary and burdensome controls.

Out of the energy chaos of the 1970's came excessive government regulation designed initially to protect consumers, well-intentioned in theory, but disastrous in consequence. In fact, government controls led to distorted prices, which further aggravated the industry by inspiring consumer demand and squelching supply. Then, believing that the gas shortage would continue, many pipelines entered into long-term contracts, incorporating onerous provisions, that committed them to above-market prices. This led producers to expand their production and consumers to conserve their gas usage. Thus, a surplus now replaced the previous shortage.

Clearly, a change was necessary. We believed a more competitive market was the key, and by focusing on these three areas, we have largely met our goal:

- Wellhead price controls, which led to shortages and surpluses, were partially lifted.
- End use restrictions, which discouraged or prohibited certain uses of gas, were removed.
- Open access to transportation to encourage competition was implemented.

Alleviating the system of profuse government restraints has permitted an economic readjustment, so that equilibrium could be reached based on supply and demand. This has aided both producers, who can expect to earn a fair price, and consumers, who have better access to adequate supplies at lower prices.

President Reagan and Prime Minister Mulroney signed the Free Trade Agreement (FTA) in recognition of our two nations' mutual commitment to avoid reverting back to the times when governments, and not the market, directed and determined industry patterns.

- The FTA will institutionalize the positive relationship that has developed, especially in the energy industry, between our two countries.

- The FTA provides the U.S. with more secure access to Canadian energy supplies.

- It offers to Canada an equally secure and sizeable market that promises to boost economic growth and expand employment.

- Greater development of U.S. and Canadian energy resources will occur once a stable structure for trade and investment has been established.

- Also, advancements in and development of North American energy resources will add to our energy security by reducing our future dependence on Persian Gulf oil.

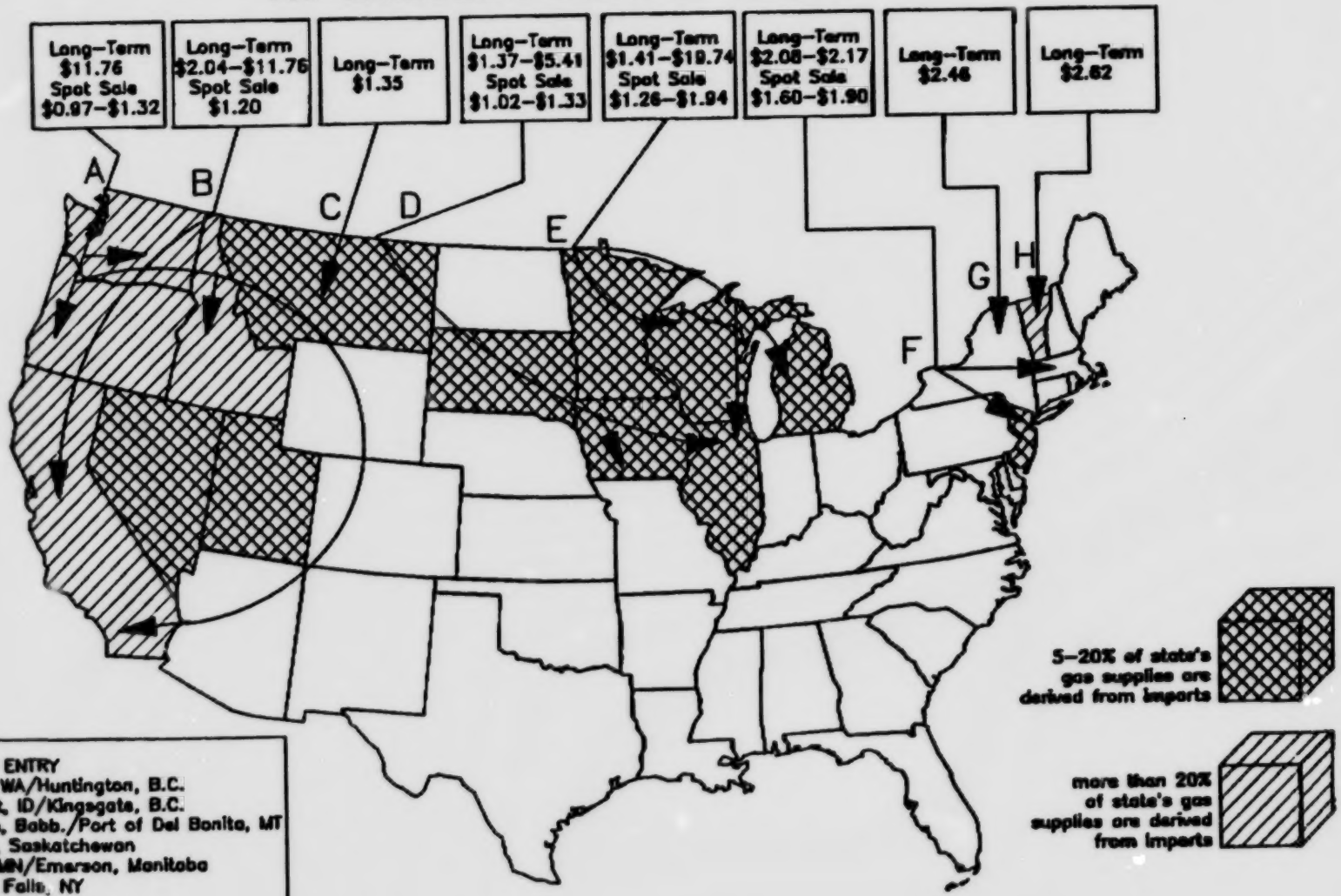
- Environmentally, natural gas has the additional benefit of mitigating some of our concern about acid rain in North America.

In conclusion, there can be no doubt that Canadian-American energy trade has benefited from deregulation. By working together, we have demonstrated that a good relationship can be made even better by mutually reinforcing cooperation.

APPENDIX A

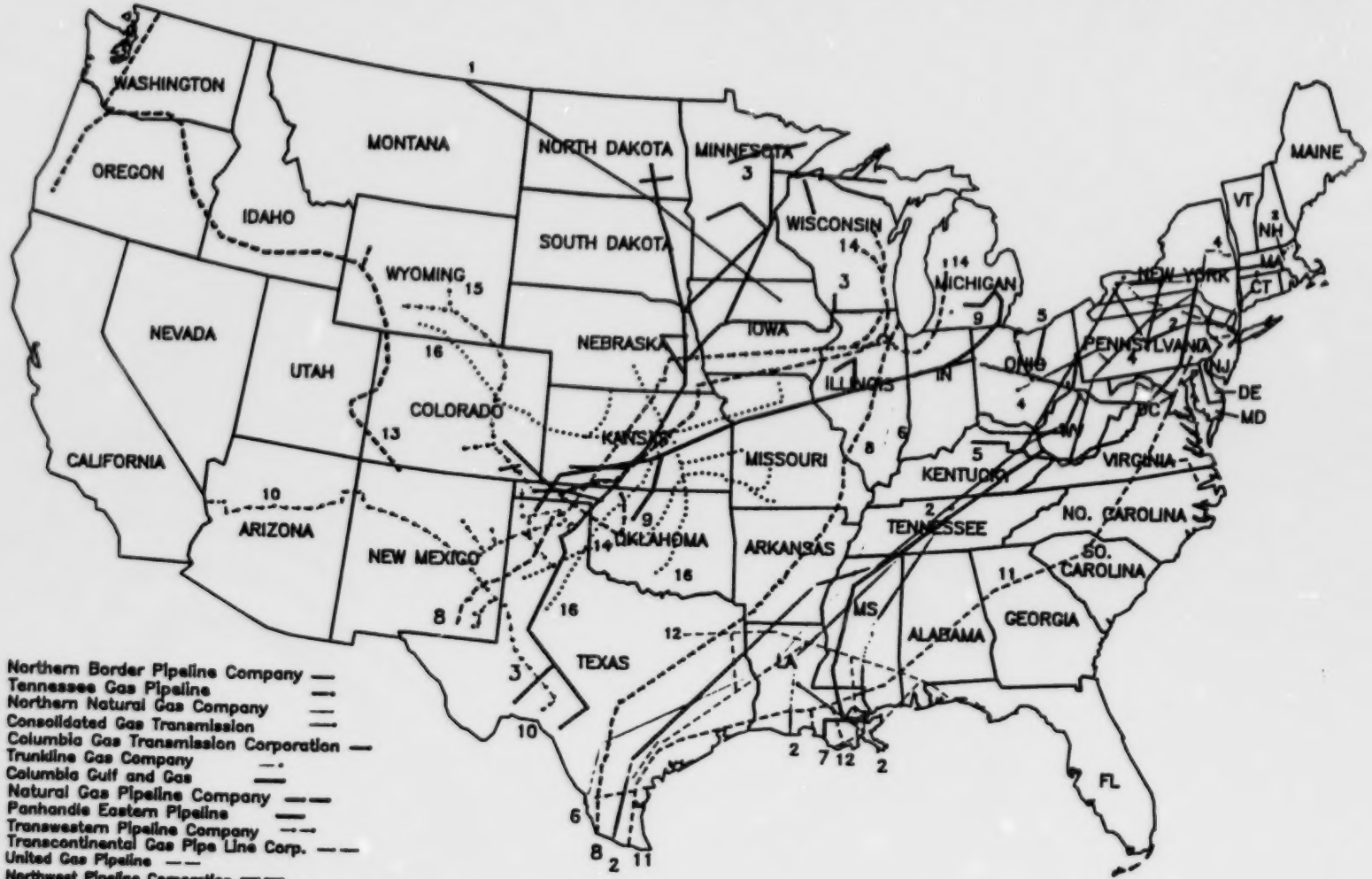
JUNE 1988

ESTIMATED PRICE RANGE ($/MMBTU) OF IMPORTED GAS AT VARIOUS POINTS OF ENTRY



POINTS OF ENTRY
A. Sumas, WA/Huntington, B.C.
B. Eastport, ID/Kingsgate, B.C.
C. Whitlash, Babb./Port of Del Bonita, MT
D. Monchy, Saskatchewan
E. Noyes, MN/Emerson, Manitoba
F. Niagara Falls, NY
G. Massena, NY
H. Highgate, VT

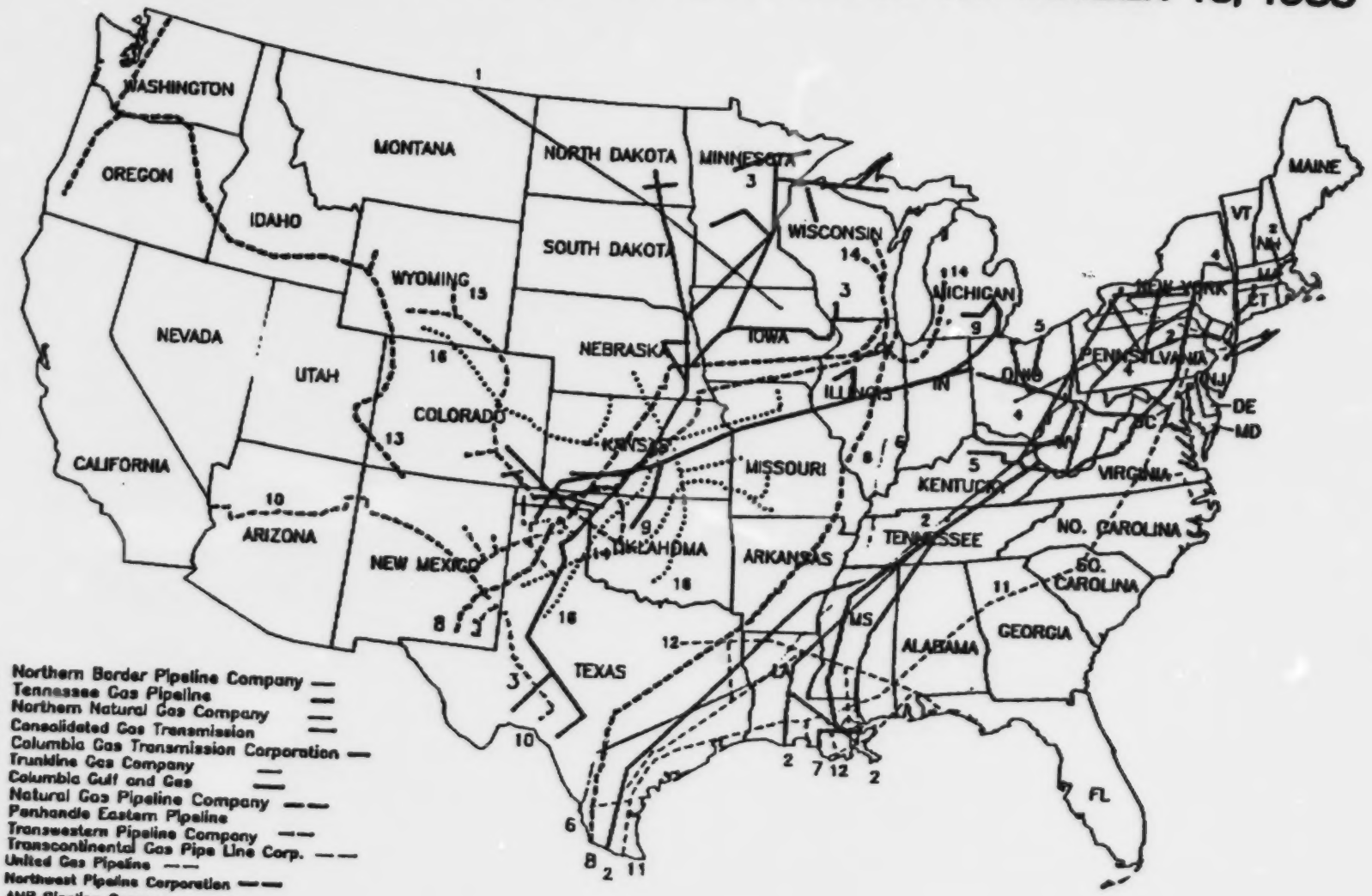
MAJOR OPEN-ACCESS CARRIERS AS OF SEPTEMBER 16, 1988



1. Northern Border Pipeline Company
2. Tennessee Gas Pipeline
3. Northern Natural Gas Company
4. Consolidated Gas Transmission
5. Columbia Gas Transmission Corporation
6. Trunkline Gas Company
7. Columbia Gulf and Gas
8. Natural Gas Pipeline Company
9. Panhandle Eastern Pipeline
10. Transwestern Pipeline Company
11. Transcontinental Gas Pipe Line Corp.
12. United Gas Pipeline
13. Northwest Pipeline Corporation
14. ANR Pipeline Company
15. Colorado Interstate
16. Williams Natural Gas Company

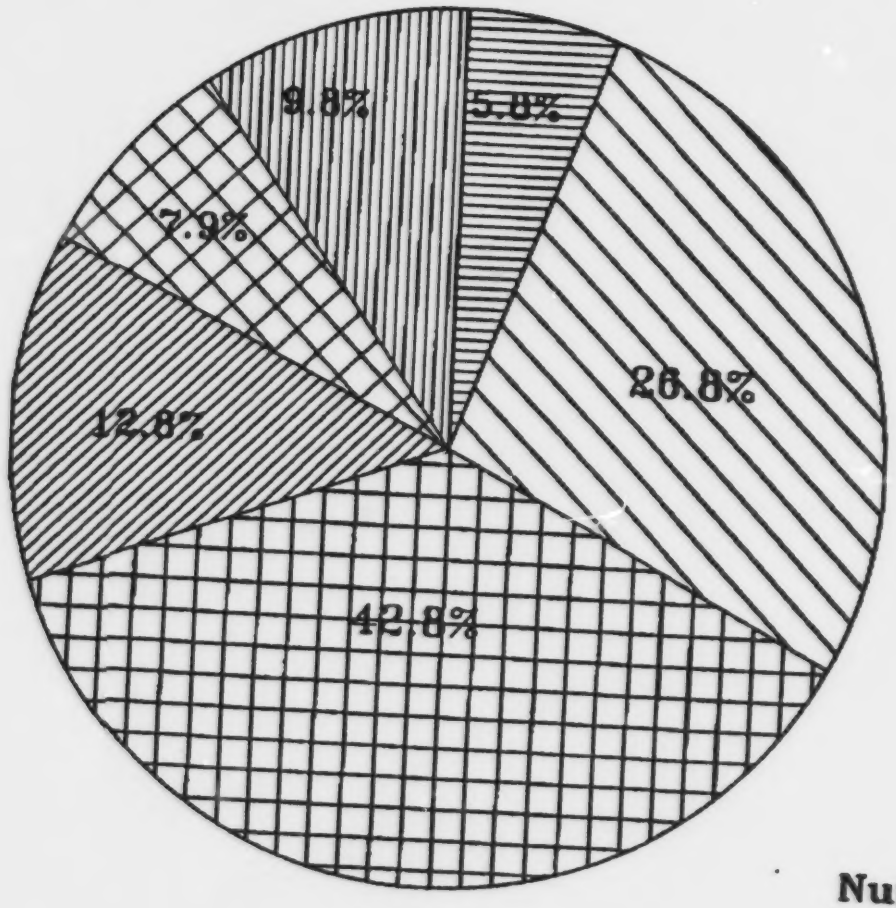
APPENDIX B

MAJOR OPEN-ACCESS CARRIERS AS OF SEPTEMBER 16, 1988



SPOT MARKET IMPORTS FROM CANADA
SECOND QUARTER 1988

APPENDIX C



- Southeast
- Pacific Northwest
- Midwest
- Northeast M-Atlantic
- California/ NV/AZ
- Misc/Unknown Market

Number of Importers – 23

INTERNATIONAL GAS TRADE DEVELOPMENTS

- REVIEW AND OUTLOOK FOR NATURAL GAS IN THE WEST EUROPEAN MARKET -

Presented by
Dr. Gerhard Enseling
Senior Vice President
Ruhrgas AG
Essen
West Germany

At
The Seventh Annual CERI
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International Gas Trade Developments

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A. The West European Markets

The horizon for natural gas in West Europe is still somewhat blurred, as dust blown up by the winds of change on the energy market during the late seventies and the eighties is still settling and forecasters are uncertain whether new storm clouds are gathering. The gas industry has been buffeted by these winds:

- Gas prices soared in 1980 and in 1981 when they were driven by the operation of heavy fuel oil and gas oil price indexation clauses.

- Optimistic demand forecasts were overshadowed by the scaled-down outlook for economic growth and by energy conservation.

- Non-petroleum competitors - coal, nuclear power and district heat - riding on the crest of the storm took advantage of the turmoil created on the energy market.

- Oil product prices slumped rapidly in 1986, when the winds subsided, eroding the new strength of non-petroleum energy sources.

The West European gas industry has not been sheltered from these winds, at least in general terms.

However, in order to describe the role played by natural gas more accurately, distinctions must be made between

- various countries with their different gas industry structures, and
- the various demand sectors.

In Western Europe, the gas industry is far from monolithic. Its history would appear to justify a classification according to the progress natural gas has achieved in the individual countries. The criteria adopted for the breakdown into

- mature markets,
- young markets, and
- incipient markets

are the age of the natural gas industry, the diversification of supplies, the expansion of the transmission and distribution systems and the penetration of natural gas in the various market sectors. This classification indicates the maturity of a gas market but gives no measure of the growth potential available for natural gas in a particular country.

The mature markets accounted for 93 % of the total gas quantity of 215 Mtoe consumed in Western Europe in 1987. For this reason, these markets dominate the prospects for gas demand in the individual market sectors.

A look at the individual market sectors shows that gas consumption in Western Europe break down as follows:

- 49 % is utilized in the residential and commercial sector,
- 26 % in the industrial sector,
- 13 % in the power station sector, and
- 12 % for other purposes.

The following sections of this paper discuss the demand perspectives in the different market sectors and developments mainly for the mature markets. The young and the incipient markets, which will only gain significance for West European gas demand in the long term, will be dealt with in more general terms.

B. The Demand Horizon

1. Residential and Commercial Market

In the residential and commercial sector, gas has made continuous progress in spite of turbulences on the energy market. Several reasons explain this steady advance:

- In most West European countries, gas oil is the main competitor of gas for residential and commercial outlets and interfuel competition between these two commodities has remained unaffected price-wise by changing energy market winds.

- Easy control, high efficiency and clean combustion are features promoting the use of gas, in particular in this sector.

- Electricity and district heat are not major competitors in most countries.

The residential and commercial market absorbed some 51 % of all gas consumed in the mature markets in 1987. The advance of gas continued even after 1978 in all major West European nations. Penetration rates have increased sharply in Italy, in France and in West Germany, and even in the United Kingdom, where the market share of gas is twice as high as the European average, substitution of other fuels by gas has still been strong. In the mature markets, one in three homes employs gas for space heating and more than 40 million dwellings have gas-fired space heating systems installed.

Undoubtedly, the prospects for gas in this sector remain promising, because the assets of natural gas are particularly valuable for residential and commercial users. Opportunities are not unlimited though, as the easily accessible market potential in the densely populated areas has already been exploited in the mature markets where population growth is low and the tapping of more marginal potentials will be costly. Specific energy consumption will also decline further, raising average gas distribution cost. And finally, the growth potential in the individual countries will be determined by the extent to which the price of imported gas or the price

paid for domestic gas will permit further expansion of gas in competition with gas oil and electricity.

Substantial differentiation would appear necessary to evaluate critically potential developments in the various national markets in Western Europe fragmentized mainly due to the different regulatory and political environments, although the internal European market should bring more harmonization. It appears reasonable to anticipate a certain concentration of residential and commercial demand in countries in which no major new distribution systems would be required to serve these users. Such mature markets have mainly developed in the Netherlands, the United Kingdom, France, Belgium, Italy and the Federal Republic of Germany. Residential and commercial gas sales, on the other hand, are likely to remain insignificant at least for the remainder of this century in incipient national markets as, for example, in Greece, Norway or Portugal, where distribution systems would still have to be built. In fact, it appears doubtful whether international gas market prices mainly determined by supply and demand in the mature markets will ever be sufficiently low to repay the high costs of new gas distribution systems in incipient markets. It would certainly not be overpessimistic to predict that entirely new residential and commercial markets will only develop in countries with

- sufficient low-priced domestic gas,
- strategic locations relative to potential sources of supply, or
- energy tax differentials stimulating gas demand.

In sum total, it would appear reasonable to anticipate that the number of dwellings heated by gas in the mature markets could rise to some 55 million by the year 2000, when about every second home would thus be equipped with a gas-fuelled space heating system.

2. Industrial Market

In the industrial sector, several trends, some of them conflicting, have led to stagnation. Final industrial energy consumption in the Federal Republic of Germany, France, Italy and the United Kingdom and in Western Europe as a whole has declined since 1978, even though industrial output has risen in these nations. The decrease in specific industrial energy consumption is attributable both to energy conservation and to structural

changes associated with the move of energy-intensive branches of industry to other regions outside Western Europe. In West Germany, for instance, one third of the reduction in specific industrial energy consumption since 1970 is explained by this transformation of industrial structures, whereas two thirds are accounted for by energy conservation. However, although overall final industrial energy consumption in Western Europe has fallen continuously, gas has more than held its own, improving its market share from 19 % in 1978 to 21 % now.

In the industrial market, inroads made by gas have been far below the penetration rate achieved in the residential and commercial market. The lower market share is partly explained by competition from coal and nuclear electricity in addition to oil product competition, and even though natural gas offers the same benefits in the industrial market as in the residential and commercial market, economies of scale tend to restrict the cost impact of differences between the properties of the various energy sources.

Whereas statistical population and household data and other reasonably predictable trends represent a relatively firm basis for residential demand forecasts, estimates for the industrial sector are much more uncertain in view of the difficulties of predicting economic growth rates and structural change. It would nevertheless appear fairly safe to expect the gas industry to strengthen its position in this sector characterized by overall energy demand stagnation. This development will mainly be at the expense of heavy fuel oil, still sold to West European industrial users at an annual rate of some 90 Mtoe.

While a competitive price is a sine qua non for gas to make progress, low-polluting combustion and easy control of gas-fired equipment are additional assets. Excellent efficiency and advanced processes such as regenerative heating are further benefits appreciated by industrial gas users.

3. Power Station Sector

Total feedstock demand for power generation has increased considerably in recent years and will continue to expand, but growth rates will not return to the levels of the seventies, when gas as a feedstock first made major inroads and then lost substantial ground as gas prices soared in the wake of the oil price hikes.

National trends, however, differ widely. Whereas gas sales to French and British power stations were already almost negligible during the seventies, West German gas consumption for electricity generation, still floating at a 14 Mtoe peak in 1979, dropped by two thirds to 5 Mtoe in 1986, initially because the oil price hikes of 1979 and 1980 gave coal and nuclear fuel a competitive edge on gas and subsequently because power station outlets were barred to gas once it had regained its competitiveness because the electricity generating industry had committed itself to the long-term purchase of domestic hard coal. On the other hand, gas has fared quite differently on the Italian and the Dutch power station markets, where it has for some time been a stopgap alternative in somewhat convoluted power generation politics, which will probably remain the case for some years.

However, - at least in theory - gas is presently enjoying a renaissance in the power generation sector as

- gas prices have returned to the level of the second half of the seventies,

- the future of nuclear energy has come into question in a number of countries,

- reservations by the public and environmental regulations hamper the construction of coal-fuelled stations, and

- cogeneration continues to make progress.

For industrial or decentralized small and medium-sized local utility cogeneration applications, gas has become a highly competitive feedstock and is likely to strengthen its market position further.

As regards conventional power generation, the uncertainties of nuclear energy make any prediction a difficult exercise. At sites where environmental standards are stringent, gas can be a strong contender even for larger conventional power station outlets and is able to hold its own, for instance, against coal offered at world market prices. The crucial factor in any such major power station project will be the gas-versus-coal price trends anticipated by electric utilities as well as the ability and willingness of gas suppliers to deliver their product to gas-fuelled power

plants on a long-term basis in line with the price development of the competing energy at the specific site which would mostly be imported coal. The view prevails that returns on the sale of gas priced against coal for power generation may presently be reasonable, but may slump at some time in the nineties and may then be unsatisfactory under binding long-term sales contracts.

The power generation option is certainly somewhat more promising in cases in which producers, at comparable electricity price levels, are able to deliver gas at significantly lower transmission cost to domestic power plants than to traditional markets abroad. Norwegian power stations would be a case on hand considering, in particular, that such sales would hardly be an alternative to the sale of gas to a foreign market, but rather represent an additional outlet.

4. Total Demand

An in-depth analysis of demand trends in the various energy market sectors shows that gas demand forecasts for the mature markets differ substantially, ranging from a small decline in consumption in the Netherlands to substantial growth in Italy. If the recently published new draft energy plan becomes reality, growth in Italy will even be more than 50 %.

In the young gas markets of Spain and Denmark, gas sales could double by the year 2000. Future energy prospects in Sweden, where the decision to abandon nuclear power has been taken, are a particularly uncertain element for estimates. Uncertainties are even greater for the incipient markets of Greece, Norway and Portugal, in which no gas industry has yet taken root. Annual gas sales in these incipient markets and in Sweden might total some 8 to 15 Mtoe by the year 2000.

The West European demand horizon, then, is not as bright as it appeared in 1977/1978, as gas demand now predicted for the year 2000 is more than a quarter lower than had been anticipated in the late seventies before the onset of the second oil price hike. However, for traditional outlets in mature markets, forecasts have hardly changed in recent years, while major uncertainties still prevail for young and for incipient markets as well as for the power station sector, where demand is difficult to estimate in view of the non-commercial decision-making processes involved. In spite of these

uncertainties, it would seem a reasonable estimate to forecast that the West European gas consumption of 215 Mtoe in 1987 boosted considerably by cold winter weather will rise to between 220 and 250 Mtoe in the year 2000.

After the turn of the century, overall West European gas consumption is unlikely to increase further, as continued growth in the incipient and the young markets will match a slight decrease in gas demand anticipated for the mature markets.

All of these trends assume, of course, that the political and the legal environments in which the gas industry operates will not change fundamentally.

C. The Supply Horizon

Supply and demand are, of course, two sides of the same coin and any gas demand forecast correlates with the quantities of gas offered by suppliers and the prices at which the commodity can be purchased.

In an industry in which long-range planning is crucial, it is, of course, the early bird that catches the worm. The West European gas industry has acted according to this principle, as demonstrated by the agreement of the Soviet natural gas project in 1981/1982, the renewal of the Dutch gas export contracts in 1984/1985, the decision on the Troll project in 1986 and additions to reserves in the consumer countries mainly by increasing the reserve base for the U.K. shelf, the Netherlands and Italy.

The structure of West European supplies is well diversified:

- 51 % of all supplies come from domestic sources;
- 22 % of the supplies are based on intra-West European trade, mainly represented by supplies from the Netherlands and from Norway;
- 27 % are imports from non-European sources, mainly from the Soviet Union and Algeria.

Norway, the Netherlands, the Soviet Union and Algeria have become the main producers of gas for the West European market due to geographical reasons, the size of their resources and the relationship between total reserves and domestic demand. In these nations, economically recoverable reserves have grown since 1977 by as much as fifty percent to approx. 50,000 billion m^3 in spite of substantial ongoing gas production.

Adequate reserves do not warrant adequate supplies, though. The reserves must be mobilized when required and the gas must be offered at competitive prices. Political willingness to export domestic resources, appropriate production and transportation technology and sufficient economic and commercial incentives are crucial factors.

In spite of the present low energy price level, the current supply outlook for Western Europe is more encouraging than ever:

- The agreement of the Troll project between Norwegian producers and buyers in continental Europe gives Norwegian gas a very strong foothold on the West European gas market. The belaboured issue as to the timing of the decision has stimulated entirely superfluous debates. Regarding the outlet for the gas, no valid argument justified further delays and the ensuing risk of losing shares in the continental gas market to other gas suppliers. Regarding the price for the gas, no valid argument will show that the gas was sold at a bargain price, since the agreements call for regular price reviews which warrant that the Norwegian suppliers will always receive the true market value for the gas and the buyers will always receive the gas at a price allowing competitive marketing. The question that remains is whether the project will be economically viable. In fact, further technical studies have led to a decrease in initial capital expenditure and operating expense estimates. These more optimistic forecasts, together with the substantial economies of scale achieved through the sale of considerable quantities of Troll gas and the modification of tax regulations in Norway, lend substantial support to the assumption that return on investment will be satisfactory, given at least a long-term rise in energy prices. The probability of such a rise in the time frame of the project is certainly not low considering that production will only commence in 1996 and will continue very far into the next century.

A more flexible approach to supply contracts is reflected by various novel arrangements fixed in the Troll agreements. On the one hand, they create for the producers the flexibility to deliver gas from other fields and, in particular, associated gas and, on the other hand, they offer the buyers the flexibility to adjust supplies to demand by exercising agreed options.

The total level of future Norwegian gas supplies is, however, still somewhat uncertain. Exports from Norway will dip to a low in the early nineties and will return to and then exceed their present level during the mid-nineties. At least two thirds of the gas produced in Norwegian waters will be absorbed by the markets of continental Europe. The largest importer of this gas will be the Federal Republic of Germany. If potential supplies to the United Kingdom and to other Scandinavian nations are added, Norwegian gas output could rise to some 60 to 65 Mtoe by the year 2005.

- Dutch gas export contracts were renewed for ten years in 1984/1985 and will now mostly expire between 2005 and 2010. The decision as to whether exports will continue beyond this time frame will have to be taken in the second half of the nineties. Apart from the Dutch reserve base, the long-term policy of using gas for electricity generation at Dutch power stations will have an important influence on this decision.

- In spite of substantial additions to British gas reserves during the eighties, the United Kingdom, Western Europe's largest gas consumer presently covering 22 % of its gas demand by gas imported from Norway, will continue to depend on imports. On balance, British fields will therefore hardly be available for gas exports to other West European nations.

- Indigenous fields met some 73 % of Western Europe's gas demand in 1987, while imports from non-European regions only accounted for approx. 27 %. Most of this gas was received from the Soviet Union and from Algeria, while imports from Libya - in terms of Western Europe as a whole - were negligible.

- The Soviet Union, where more than 38 % of the world's natural gas resources are located, is continuing to develop its West Siberian fields at a breathtaking pace. Annual output may well rise to 1,000 billion m^3 by the end of this century. Firm exports to Western Europe in the early nineties will run at more than 50 billion m^3/year, equivalent to only 6 % of Soviet gas production. The Soviets are interested in expanding these exports initially by selling gas to new markets.

  The gas imported by buyers in Western Europe is produced in distant Siberia under harsh climatic conditions, but the fields are very large allowing substantial economies of scale regarding both production and transmission.

- Algeria is today a major gas supplier to countries in southern Europe and to Belgium. New gas markets, such as Greece and Portugal, could be developed by benefitting from the flexibility offered by liquefied natural gas technology provided that the gas is sold at prices allowing market development, even if certain initial incentives promoting the introduction of gas may be called for.

  The Algerian policy now seems to focus on LNG sales into new markets mainly in the Mediterranian region in countries such as Greece, Turkey and Portugal and efforts are being made to revive Algerian LNG exports into the North American market.

  With reserves totalling 3,000 billion m^3, Algerian gas resources are sufficiently large to serve markets in north-western Europe, too. However, the cost of taking gas from Algeria to these markets is considerable and the future must show in how far Algerian gas will be competitive in this part of Western Europe. One potential outlet would be the Federal Republic of Germany where gas companies have expressed their interest in a further diversification of their sources of supply and have announced that they would be willing to initiate a small project even during the nineties if such a project satisfies their criteria with regard to economics, reliability and long-term supply potential.

- Nigeria is a further potential source of supply for Western Europe. Regarding the project proposed for the mid-nineties, anticipated West European demand developments and economics remain crucial uncertainties. The deployment of laid-up LNG carriers would notably reduce the cost disadvantage associated with the long haul between Nigeria and the coast of Western Europe.

- And Canada? Can Western Europe become a market for Canadian LNG? It was stated during a CERI International Oil and Gas Conference five years ago that the Canadian Arctic may also be a potential source of supplies, if seen in a long-term light. It was for this reason that at the beginning of the eighties Ruhrgas, together with Canadian companies, considered a project to export Canadian LNG to Western Europe. In realistic terms, the time frame for such a project must be moved further into the future, because the economics of such a high-cost project are hardly attractive to Canadian producers after the energy price slump as price rise scenarios are presently hardly optimistic. Nevertheless, developments in Canada will be closely followed and interest in the Canadian gas industry will continue to be lively.

At the supply end, market conditions prevailing for Western Europe may be considered comfortable. Firm supplies under existing import contracts to Western Europe and intra-West European trade contracts as well as from estimated indigenous production for domestic consumption already cover more than 90 % of demand predicted for the year 2000. However, firm gas supplies vary considerably from country to country. Whereas the British gas industry must still secure substantial quantities of gas to cover demand predicted for the year 2000, gas companies in countries such as Belgium, the Federal Republic of Germany, France and Italy have already bought most or all gas needed to serve their markets for the rest of the century.

The share of supplies from the Soviet Union will increase from 17 % to approx. 19 %, while Algerian gas will raise its share from 9 % to 12 %. If no new imports from sources outside Western Europe are agreed, gas imports will thus continue to meet less than one third of European demand around the turn of the century.

Opportunities for new sales to the West European market are substantially better both for existing and for new suppliers if the gas is offered for delivery after the turn of the century. As output from fields in many West European nations will decline and most Dutch gas export contracts will expire early next century, new purchases totalling approx. 25 - 30 Mtoe/year for the period between 2000 and 2010 must be made. Norwegian, Soviet and Algerian exports could fetch a large part of this new market.

Considering the energy price level most analysts predict for the 21st century, imports from Nigeria, Qatar and also Canada could well be competitive.

The infrastructure necessary for taking gas from Norway, West Siberia and Algeria to the markets of Western Europe has already been created, as major north/south, south/north and east/west pipelines and LNG terminals were built for specific projects. It must be remembered that their capacities have been designed for individual project needs, but their interconnections are an important backbone, allowing the West European gas industry to handle hypothetical disruptions in supplies.

It is a fact that the West European gas industry cooperates more closely than any other energy industry. Intra-West European gas trading, for instance, is much more developed than intra-European trading in electricity or coal. Cross-border trading of electricity between West European nations is equivalent to less than one fifth of international gas trading in Western Europe. Some 50 % of all gas consumed in Western Europe is traded across international borders.

The horizon for natural gas in Western Europe is, however, somewhat overshadowed by clouds. Two subjects from the wide scope that exists for potential political intervention in the strucure and organization of the West European gas industry are issues of particular concern:

- The common carrier issue in the context of the creation of the single European market by the end of 1992,

- energy taxation and, in particular, the introduction of a natural gas tax.

The first subject focusses on whether utilities should be obligated to grand competitors access to their pipelines and to transport energy for competitors at the expense of their own sales. Although the problem has so far only emerged in the electricity industry, supporters of this approach also apply their philosophy to the gas industry.

It is doubtful whether this theory, should it become practice, would actually change the gas world in Western Europe. The situation in Western Europe and the state of affairs in the U.S. are entirely different. Unlike the United States, there are not thousands of small and medium-sized producers in the European Communities who must use pipelines owned by other in order to take their gas to their customers, but rather only a few major producers; two thirds of demand are met by four suppliers alone, the Soviet Union, the Netherlands, Norway and Algeria. Again, unlike the United States, there is no surplus of low-price gas in Western Europe flooding the market with no customers to take it.

In further contrast to the United States, there are no major problems regarding take or pay obligations; on the contrary, the major gas import agreements could not survive without this obligation. And no utility in Western Europe will have to face the death spiral.

For all of these reasons, it is obvious that the approach adopted in the United States cannot be applied to the European gas industry without causing considerable drawbacks in terms of security of supplies and price competitiveness for the vast majority of end users. One can expect that this view will also prevail in the current discussions.

The second subject has particularly disturbing overtones: against the background of low energy prices, pressure for an increase in taxes on energy is growing in certain countries. A variety of arguments in favor of higher energy taxes is presented, the most common argument being that low prices could once again lead to a waste of energy which must be prevented by and artificial increase in prices.

With specific reference to West Germany, the energy tax debate has sparked off a discussion on actually introducing a natural gas tax. Support for such a tax stems primarily from budget problems and not from energy policy requirements.

A tax on natural gas would in fact be counterproductive in terms of energy policy, as it would impose restraints on an energy which makes a decisive contribution to the diversification of energy sources and to the security of supplies as well as to the protection of the environment.

D. Conclusions

The structures of the West European gas industry have mastered the challenge of the 1986 oil price slump and the West European gas industry has gathered new strength during a process of adaptation which has shown that contract mechanisms developed to adjust gas prices to changing market conditions are an adequate tool to handle the vagaries of the energy market.

As for future horizons, the West European gas industry must accept that the part of the energy market on which it sells its commodity will only grow at a very slow rate, if at all. However, in view of the excellent product properties of natural gas, the gas industry may further strengthen its position by displacing other sources of energy if gas can be offered at competitive prices. However, regulatory zeal is putting a greater burden on the gas industry in some countries than is necessary.

Limited resources are today not an issue. On the contrary, new outlets to be served by an efficient utility system are sought for the mature markets and the development of gas markets in regions not yet using natural gas is under study.

For most West European nations, the long-term supply outlook is better than ever. Indigenous sources will continue to provide some two thirds of all gas beyond the turn of the century while imports from the Soviet Union, from Algeria and possibly from new non-European sources will cover the remaining demand.

U.S. MARKETS FOR IMPORTED NATURAL GAS

Presented by
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Vice President
Strategic Analysis and Energy Forecasting
Gas Research Institute
Washington, D.C.

At
The Seventh Annual CERI
International Oil and Gas Markets Conference
September 18-20, 1988
Convention Centre
Calgary, Alberta

1988 GRI BASELINE PROJECTION OF U.S. ENERGY SUPPLY AND DEMAND

Strategic Analysis and Energy
Forecasting Division

U.S. MARKETS FOR IMPORTED NATURAL GAS

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Introduction

(Slide 1) Because of the magnitude of U.S. energy markets and the position of the U.S., now and for the foreseeable future, as a net importer of both oil and gas, the dynamics of U.S. energy supply and demand will be the determining factor in the outlook for the crossborder gas trade.

In predicting these market dynamics, the most common error is to assume a large degree of uniformity among the requirements for gas and to assign a large degree of flexibility to requirements for energy of all types.

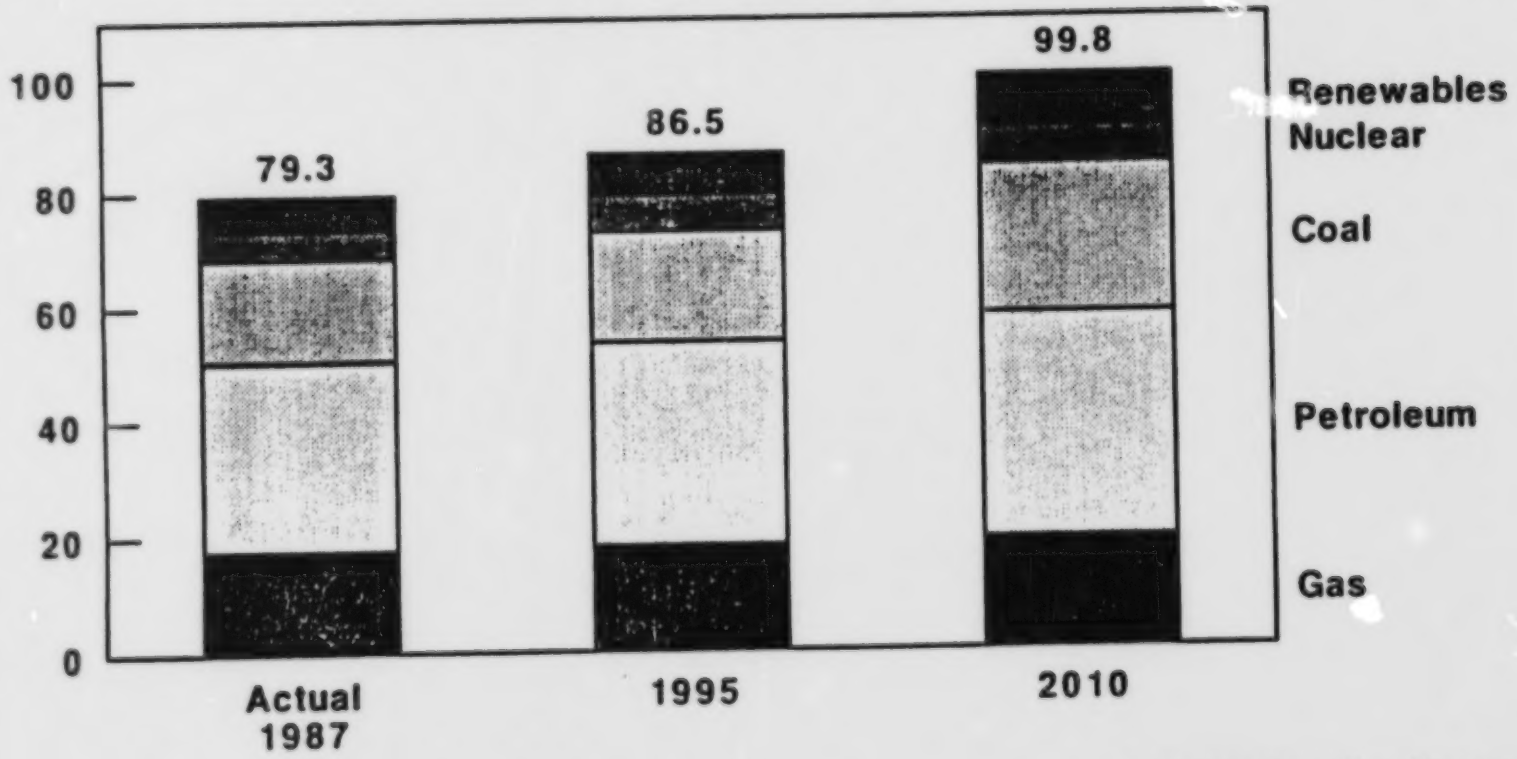
This is the kind of reasoning that presumes that if energy demand increases one percent annually, and gas is competitively priced, gas demand should share proportionately in that increase. Or, if gas enjoys a 30 percent market share in the industrial sector, aggressive marketing should be able to make it 40 percent.

The facts of life are very different. The uses for gas are very diversified and discreet. There are energy market sectors so dominated by gas that any expansion of market share is improbable and there are large energy markets in which gas does not and is unlikely to compete (aircraft fuels, for example). There are also potential gas users, even in the U.S., who do not have physical access to the gas pipeline system. They cannot choose gas regardless of the economics.

In my presentation, which is based upon the 1988 GRI Baseline Projection of U.S. Energy Supply and Demand, I will try to stress the nature of gas markets and the constraints upon those markets. Then I will outline the role of imported gas within the portfolio of supply sources as we see it developing.

PRIMARY ENERGY CONSUMPTION

(Quads)



1988 GRI Baseline Projection

Primary Energy Consumption

A. Introduction

(Slide 2) The Baseline Projection indicates that total U.S. primary energy consumption will increase about one percent annually or less than one-half of the projected rate of growth in GNP over the long term. The energy intensity of the economy, therefore, is declining throughout the projection, reflecting continued efficiencies of energy utilization and continued economic restructuring away from energy intensive activity.

The projected overall balance among the primary energy sources which provide the ultimate energy services is rational and achievable based upon current policies and projected economic trends. A significant disruption in any major energy supply source, however, would be difficult to accommodate.

B. Petroleum

GRI's projected track for world oil prices assumes rough stability at about the current price level until after 1990, a tightening market with real price escalation beginning in the '90s and increasing escalation after 2000, as Middle East sources again dominate supply. U.S. refiner acquisition costs, in current dollars, reach about 27 dollars in 2000 and 42 dollars in 2010.

At these prices, U.S. petroleum consumption is projected to increase at a rate slightly below that of total energy demand. Although about half of the increase occurs in transportation uses, demand growth is substantial in industrial uses, particularly feedstocks. Increased use of petroleum by electric utilities in existing oil-burning facilities and new peaking units is also expected.

Domestic petroleum production is projected to decline from nearly 10 million barrels per day in 1987 to 6.6 million in 2010. Oil imports, therefore, would reach 12.4 million barrels per day by 2010.

C. Coal

Coal consumption is projected to grow at the average rate of 1.7 percent annually, much more rapidly than overall energy demand. The predominant increase in coal use, of course, is in the generation of electricity. It reflects a projected rate of increase in the requirement for electricity of about 78 percent of GNP growth. This increase in electrical demand, moreover, is below that in many contemporary projections. This projection does not assume any new environmental constraint which would further restrict or impose significant new economic burdens upon the use of coal.

D. Nuclear

The projection assumes only the completion of the nuclear powerplants currently under construction and the continued operation of those plants which have not been affected by policy restrictions.

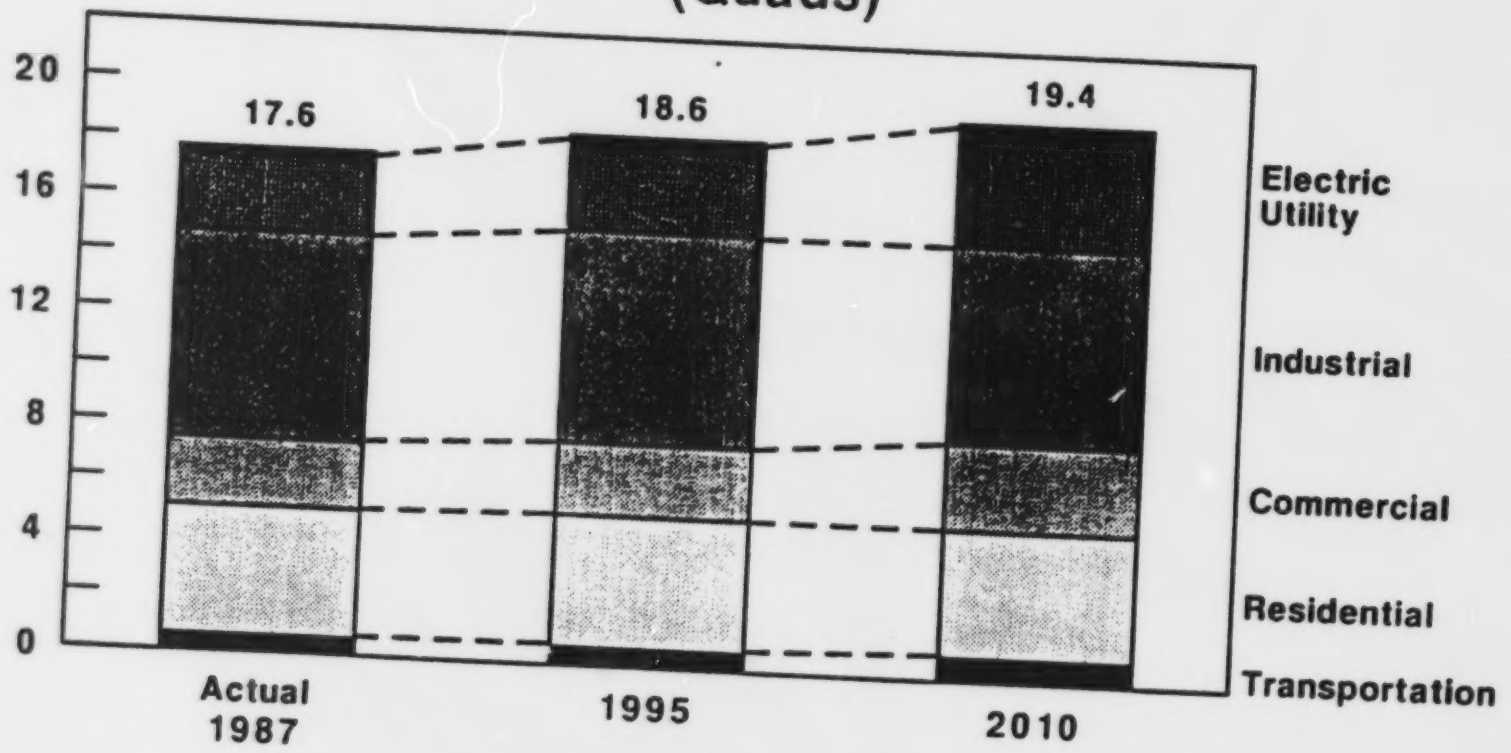
E. Gas

Natural gas consumption is projected to grow at an average annual rate of 0.4 percent. While this represents a stable market outlook, it involves shifts between diminishing traditional uses and increasing requirements in certain sectors.

This projection includes no estimate of potential demand for natural gas to serve new environmental functions, such as powerplant emission control, waste incineration, or large scale transportation use, although I will discuss these uses later.

GAS DEMAND BY SECTOR

(Quads)



1988 GRI Baseline Projection

Gas Demand by Sector

A. Residential

(Slide 3) Space heating represents the major portion of residential energy consumption, about 60 percent. The gas share of the space heating market in new single family homes has been increasing. The total number of gas heating customers is projected to continue to increase, from 52 million in 1987 to 67 million in 2010. The dramatic efficiency improvements in equipment and housing, however, will hold overall residential energy demand and the natural gas portion relatively flat.

B. Commercial

A projected high rate of economic growth in the commercial sector translates into substantial increases in energy demand despite continuing efficiency improvements. Most of the increased demand is for space conditioning and for inherently electrical services such as lighting and communications. Space conditioning fuel choices are strongly influenced by the cooling component.

The natural gas share of commercial energy demand will depend heavily upon the success of gas cooling and cogeneration technologies. This projection reflects an increase in the gas share of commercial space cooling from 5 percent today to 16 percent in 2010, based upon penetration of cogeneration; double-effect, direct-fired absorption chillers; and gas-fired heat pumps.

C. Industrial

After nearly a decade of steady decline, industrial consumption of energy turned up sharply in 1987 and natural gas participated in the trend reversal. The growth has remained strong in early 1988. Low energy prices and a resurgence in the export market have influenced the recent experience.

However, it may also signal a slowing or end of the erosion of the U.S. heavy industry base. Gradual future growth in industrial energy demand is anticipated.

There are two major components of industrial gas markets. The competition with low-priced residual fuel oil and coal for the boiler market, which represents 39 percent of industrial gas demand, will continue to depend upon competitive pricing of gas. The best opportunity to increase the gas share of this market will be through cogeneration applications. The second component, process heat applications, is diverse. Competition between gas and electricity will increase in these applications and gas technologies will have to keep pace with evolving industrial processes.

D. Electric Utilities

The projected growth in electricity demand will provide an opportunity for increased use of natural gas by electric utilities. As the demand for electricity outstrips the capacity of existing electric generating facilities, initially at times of peak demand and later more generally, gas will offer a competitive edge for new peaking facilities using combined-cycle technology. That technology has relatively low capital costs and short construction lead time. Repowering of existing gas-fired powerplants along with greater operating time will also add to gas consumption in the utility sector.

The available gas-based generating technologies are clearly competitive for a large share of new capacity within the price tracks in this projection. The major uncertainty is the degree of confidence utility managers will have in the continued price stability and reliability of supply of natural gas over the life of new capital investments.

E. Transportation

Gas demand in the transportation sector is primarily that consumed by pipeline compressor stations.

F. Uncertainties

The uncertainties regarding the future role of natural gas implicit in the Baseline Projection lie predominantly in the direction of a greater requirement for gas. For example:

- Any policy restriction or new economic burden placed upon a major alternative energy source, such as coal, imported oil, or nuclear generation, would increase the gas requirement;

- Emerging environmental uses might represent major new markets for gas; or

- New technologies could increase the gas share of traditional end use services.

INCREASED ENVIRONMENTAL POLICY EMPHASIS

Applications Examined	Incremental Gas Requirement in 2010 (Quads)
Incineration	
Municipal Waste	0.2 - 0.4
Hazardous Waste	0.1 - 0.3
Vehicle Fuel Substitution	
Gasoline	0.2 - 0.4
Diesel	0.3 - 0.4
Air Quality Control	
Industrial	0.4 - 1.1
Electric Utility	0.2 - 2.7

Analyses of Alternative Futures

Increased Environmental Policy Emphasis

(Slide 4) Thus far, we have not included in the Baseline Projection any estimate of the potential markets for gas that might emerge from tightened environmental regulations or from new applications for gas technologies that respond to emerging environmental problems. We have not done so because, either:

- the technical capabilities and economics of the technologies are not yet adequately established to estimate the extent of their potential applicability, or

- the new policies that will create the markets are not yet known and, in most cases, the policies will not only create the market but will also control the viability of the gas options.

The estimated potential for incremental gas demand based upon assumptions of new policy initiatives is shown in the Table.

A. Incineration

Existing policies have created the need for innovative waste disposal techniques. Gas is a candidate for use as a supplemental fuel for incineration.

The incineration of municipal solid waste and sewage sludge increasingly will be substituted for landfill disposal. Gas offers advantages in the control of trace contaminants, NO_x, and fly ash in incineration applications. It also enhances the efficiency of waste as a fuel for electric generation.

Hazardous wastes currently are being incinerated in boilers. As standards for the control of emissions become more stringent, gas may become more extensively used.

B. Vehicle Fuel

There is also increasing emphasis upon diversifying vehicle fuels away from petroleum liquids, primarily for air quality reasons. Compressed natural gas has been a potential alternative for some time, but has not penetrated the market because of the lack of a vehicle supply system for compressed gas and only marginal economic advantages. The high end of the ranges shown would imply substantial fleet use of CNG, some penetration of the private automobile market, and use of CNG to meet the 1991 environmental standards for diesel engines.

C. Air Quality

The estimates of air quality applications assume the adoption of more stringent regulations for emissions from existing industrial boilers and electric powerplants.

The industrial estimate is not necessarily related to the electric generation use, as differing regulations would be involved in each. The upper limits of the estimated gas use are based upon an assumption that the gas cofiring will be optimum at 15 percent of plant fuel consumption.

Please note that there is no total on the slide. The circumstances necessary to induce these gas requirements are not necessarily interrelated.

ENVIRONMENTAL USES OF GAS

High Competitive Value

Incineration

- Municipal Waste
- Hazardous Waste

Vehicle Fuel Substitution

Low Competitive Value

Air Quality Control

- Industrial Sector
- Electric Powerplants

Environmental Uses of Gas

(Slide 5) As this slide indicates, the potential environmental applications for natural gas vary with regard to the value that can be assigned to the fuel in a competitive market.

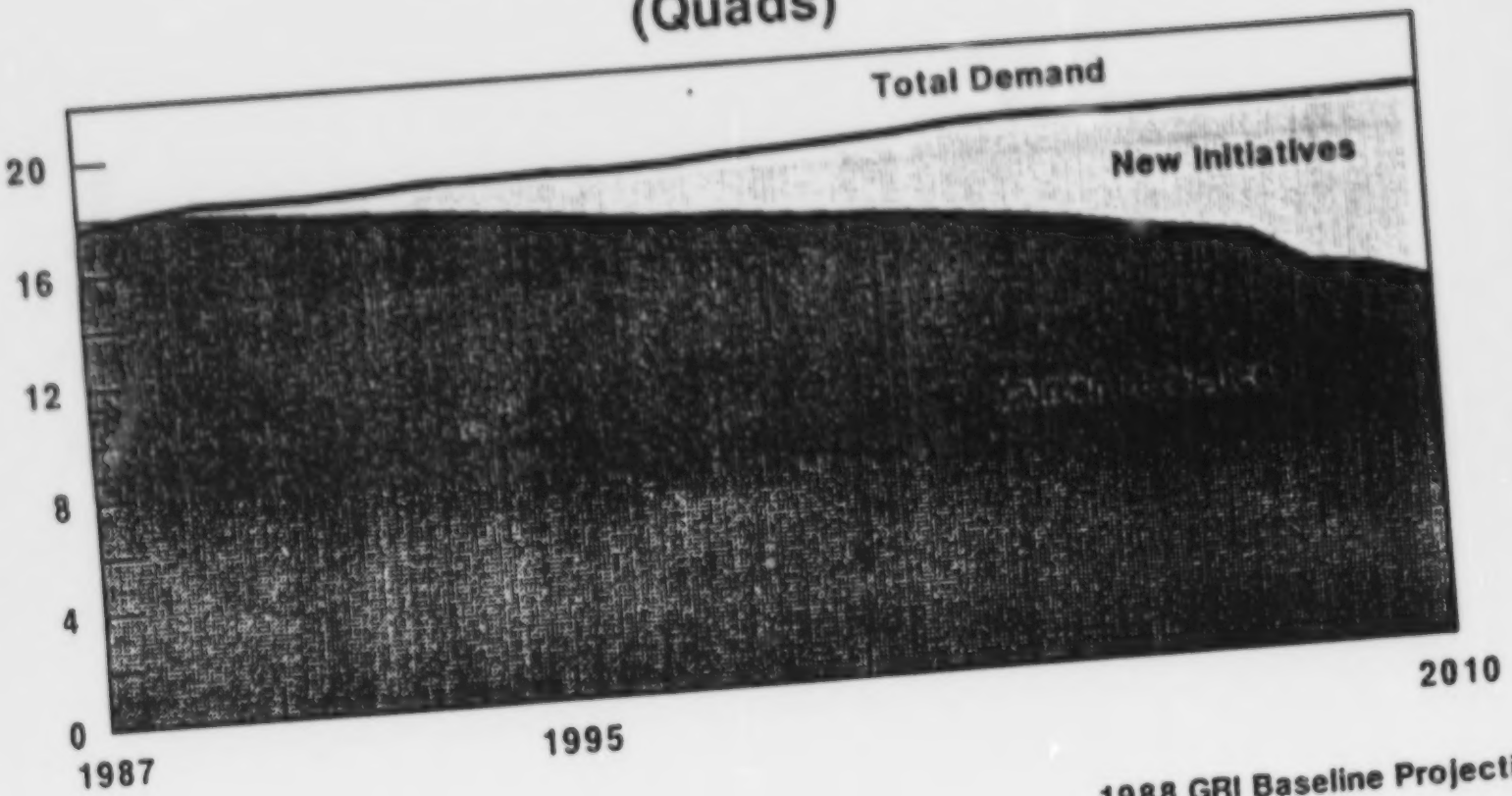
Waste disposal is a costly activity and options are becoming scarce. An ideal supplemental fuel which can achieve the requirements imposed on emissions and residue can command a premium price. Similarly, if a severe air quality imperative is placed upon vehicle emissions in metropolitan areas, CNG may be competitive at relatively high natural gas prices.

On the other hand, most air quality uses of gas in stationary applications will compete against the capital costs of scrubbers or other techniques that can comply with the standards using coal. The price of gas in this competition will have to remain relatively low.

If significant environmental demands for gas do evolve, therefore, they may not be entirely additive to existing markets. The high value applications, for example, may bid gas away from current low value uses such as boiler fuel. Full realization of the market potential of the lower value uses for gas will depend upon the gas industry's ability to increase gas deliverability while keeping the delivered price relatively low. Of course, stringent restrictions or outright prohibitions on the use of alternative fuels in these applications would increase the value of the gas and the price that could be supported.

COMPOSITION OF GAS SUPPLY

(Quads)



1988 GRI Baseline Projection

Composition of Gas Supply

(Slide 6) The gas supply outlook for the Baseline Projection represents a portfolio of supply sources that can be developed at acquisition prices consistent with the delivered prices used in the demand analysis.

It is useful to separate the supply sources into two groups:

- those sources that are playing a role in the current supply picture and can be projected based upon that experience, called "current practice" on the slide, and

- those sources that will require "new initiatives" on the part of the gas industry to become available.

To some extent the "current practice" sources, which are dominated by conventional gas production in the lower-48 states, have greater credibility in projections of supply reliability. As this slide shows, at prices competitive with alternative fuels, new initiatives will be required to meet 7 percent of projected gas requirements in 1995 and 34 percent in 2010.

GAS SUPPLY SOURCES
(Quads)

	Actual 1987	1995	2010
Current Practice			
Domestic Production	16.9	15.5	10.6
Canadian Imports	1.0	1.6	1.3
LNG Imports	0.0	0.2	0.8
Supplemental Sources	0.2	0.3	0.4
	18.1	17.6	13.1
New Initiatives			
Lower-48 Adv. Tech.	0.0	1.4	4.8
Alaskan Pipeline	0.0	0.0	1.3
Canadian Frontier	0.0	0.0	0.3
Other Imports	0.0	0.0	0.2
Synthetics	0.0	0.0	0.1
	0.0	1.4	6.7
Total Supply	18.1	19.0	19.8

1988 GRI Baseline Projection

Gas Supply Sources

(Slide 7) This table presents a more detailed account of the projected supply sources.

The first line of the table presents production from domestic gas resources using technologies which would be called "conventional" in the field. Although it is expected to decline, it remains the mainstay of future supply. Much of the controversy and uncertainty expressed over the gas supply outlook concerns the range of optimism about the rate of decline in domestic conventional production, and the future wellhead prices that will be required to bring forth the supply.

The projected Canadian imports from producing regions are well within the physical capability of the resources. In the schedule shown, however, deliveries are lower in the near-term and higher in the long-term than the usual Canadian expectations.

The lower part of the table portrays the portfolio of "new initiatives" that we have arrived at to round out the supply. The contribution to domestic production resulting from new technology represents a critical component. The amount shown in the table is based upon estimates of production from tight formations, coal seams, and watered out reservoirs. This contribution should be viewed as extending conventional domestic production by bringing advanced techniques and practices into conventional use.

The resources available to advanced technology are very large. The limiting factor, and the uncertainty, concerning this contribution is the pace at which the predictability and reliability of new production techniques can be demonstrated in the field and brought into widespread use, in other words become the "conventional" practices.

This is not, however, a speculative estimate. For example, during the few years I have been making these annual presentations, production of coalbed methane has arrived at the point where it is a candidate to move up to the

"conventional practice" part of the Table. About 200 coalbed gas wells were drilled in 1987 and the number may double this year. GRI's activities in developing and disseminating technical data has played a prominent role in stimulating this activity.

This projection does not include any estimate of the potential contribution of incremental gas recovery from conventional reservoirs using more intensive production techniques. The new theories of intensive development of oil fields are beginning to bear fruit in the field. GRI has been involved in both the theoretical and practical aspects of extending this theory and practice to non-associated gas fields, but we have not yet arrived at an estimate of the potential impact of this extension of "conventional practice."

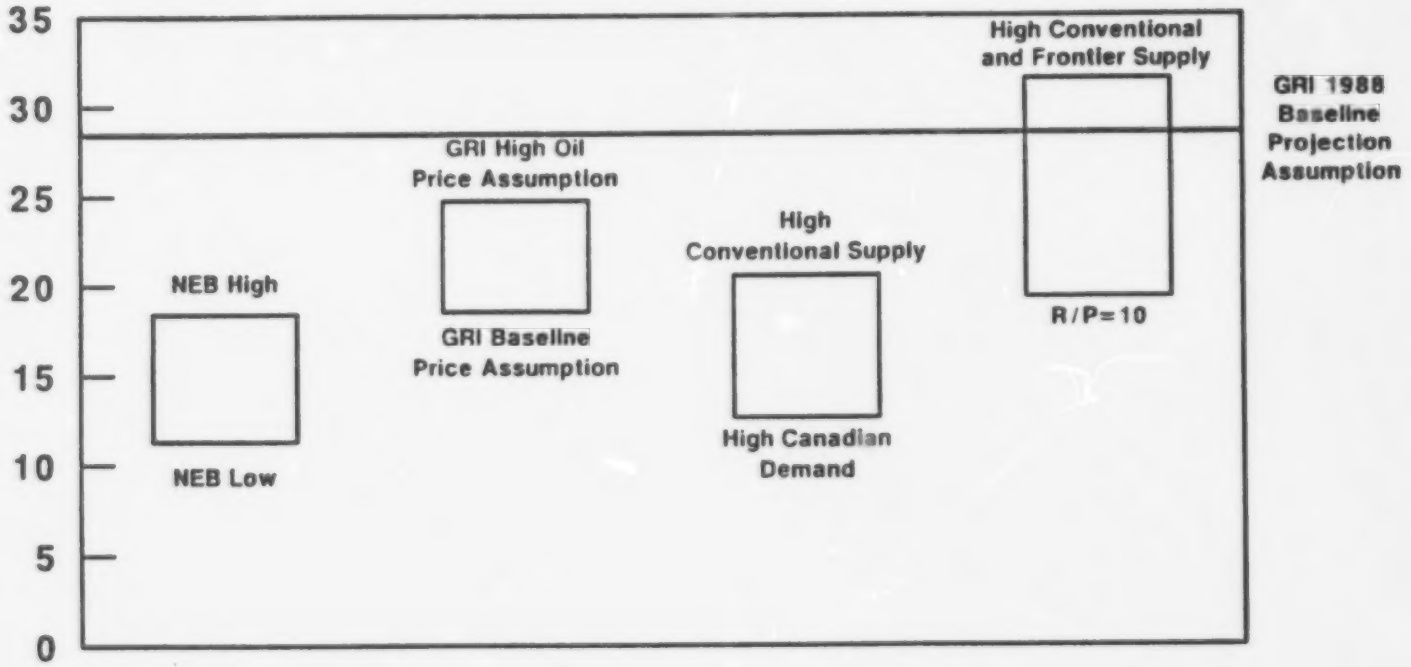
Renewed deliveries of LNG up to the capacity of existing terminals, which we have been projecting for several years, are now generally expected. LNG imports requiring new facilities and renewed imports from Mexico would have economic viability in the later years of the projection, but will depend upon political factors.

Canadian frontier gas and pipeline deliveries from Alaska will depend upon large-scale capital investments. The energy price outlook in this projection can provide adequate returns on those investments in the time frames we have assumed.

Timely initiation of Canadian frontier development also is probably a political requirement for the full realization of the imports shown in the top portion of the Table.

CUMULATIVE CANADIAN NATURAL GAS EXPORTS, 1987-2005

(Tcf)



Cumulative Canadian Exports

(Slide 8) It is evident from the preceding discussion that the availability of Canadian gas imports, at prices competitive with alternative fuels at the burnertip, is an essential element of a U.S. gas supply and demand balance. The GRI Baseline Projection, like most U.S. forecasts, shows the requirement for Canadian gas imports growing only gradually over the near-term but sustained at relatively high levels in the late 1990s and beyond.

We have tested the cumulative Canadian gas deliveries expected in the GRI Baseline Projection against a variety of assumptions. All of these alternatives were predicated on a judgment that Canadian policy will continue to require an assurance of protection for the "reasonably foreseeable" Canadian domestic requirements. In more simplistic terms, we examined a set of scenarios with one exception using the NEB's former 15 to 1 R/P ratio as a yardstick of Canadian requirements.

This slide summarizes the results. Each square shows a range of cumulative exports available under a set of assumptions:

- The high and low NEB oil price cases of domestic supply and demand extended to 2005;

- The NEB analysis modified to use a range of GRI oil price assumptions;

- Some alternative assumptions of Canadian supply and demand;

- And, finally, a case with relatively high estimates of both conventional and frontier productions and a case with a somewhat reduced R/P ratio.

The line struck across the slide represents the cumulative requirement to satisfy the GRI Baseline Projection of Canadian imports into the U.S. through the year 2005.

Clearly, the implication is that the Baseline Projection is optimistic. Delivery of this level of Canadian supply will require

- A healthy and aggressive investment program in Canada for both conventional and frontier resources along with delivery infrastructure; and

- A consistently benevolent attitude by policymakers in both countries to encourage the cross border gas trade.

In this light, the Canadian potential is not that much different from any other gas supply source or, indeed, any other energy source of any kind. The future contributions from coal, oil, and electricity (especially nuclear generation), will all depend upon both aggressive investment programs by industry and enlightened policy on the part of governments.

We continue to be optimistic about the availability of Canadian gas and continue to assume that in our U.S. supply slate.

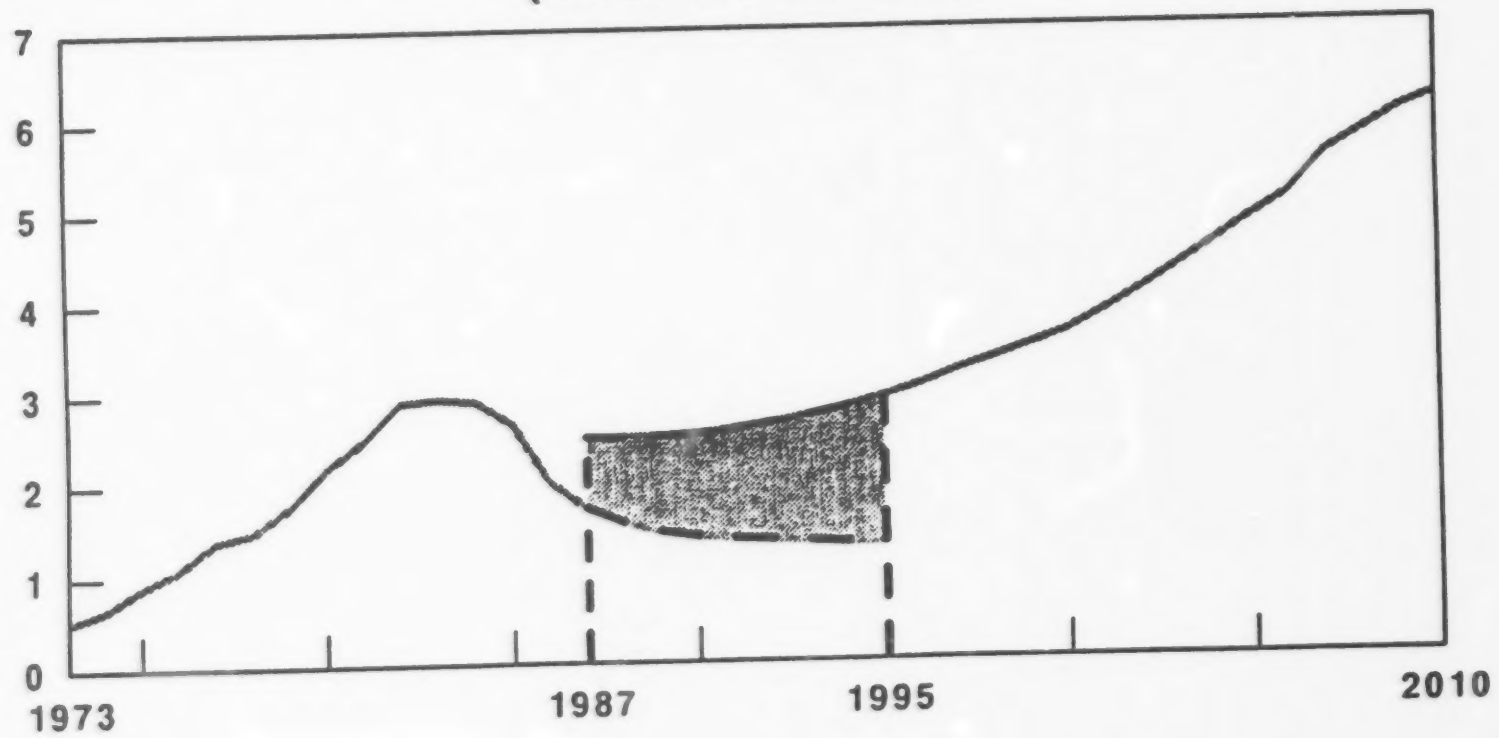
There remains, however, an important difference in perspective between the U.S. and Canadian view of the gas trade.

U.S. projections, such as GRI's, assume that Canadian gas will penetrate U.S. markets only as the U.S. domestic supply requires greater and greater amounts of investment in new production capability. Canadian expectations, on the other hand, expect the U.S. market to absorb the early production capacity surplus to Canadian requirements.

The result is likely to be intense price competition in the near-term. The schedule of actual deliveries under the policies espoused by the Free Trade Agreement ultimately will be decided, not by anybody's projection, but by the marketplace.

GAS ACQUISITION PRICES

(1987$ / MMBtu)



1988 GRI Baseline Projection

Gas Acquisition Prices

(Slide 9) This figure presents the trend in the acquisition price for gas. This is a weighted average price for all sources at the point of entry into the U.S. transportation system. It reflects a variety of factors, for example the declining volumes of gas that are still under Federal price regulation.

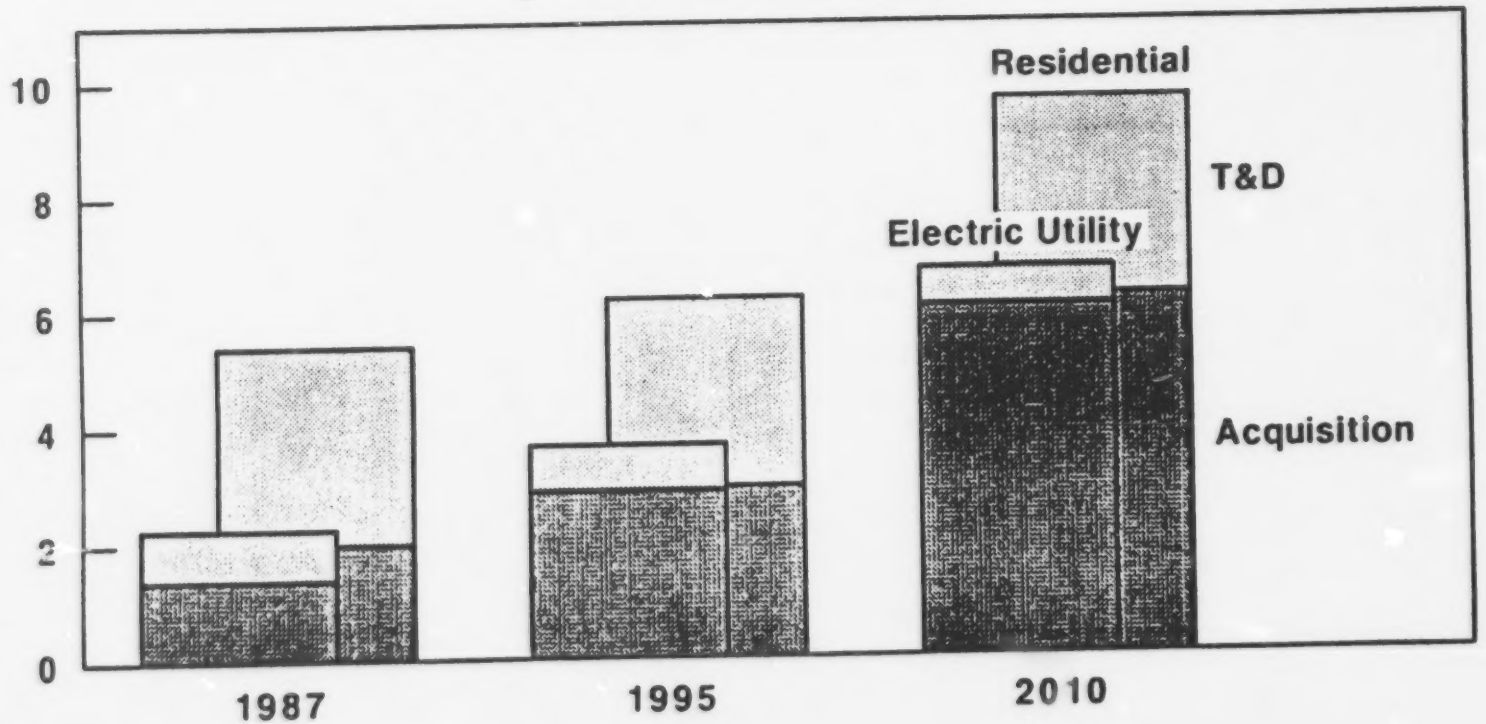
The gas price trend developed in the Baseline Projection is constrained on the one hand by the pressures of interfuel price competition at the burner tip, but it is driven on the production side by the need to price future supply more compatibly with its long-run replacement costs. During the early 1990s, it is reasonable to expect the "gas bubble" to be absorbed, eliminating the downward pressures of gas-to-gas competition at the wellhead. At that point, lower-48 gas prices will have to rise to a level adequate to attract new investment to support increased exploration and development activity.

The timing and pattern of this price adjustment will depend upon near-term factors, such as economic cycles and weather, that are not amenable to long-range projection methodology. The range of possible transitions is shown by the envelope in the figure.

If petroleum prices remain low for a longer period, as the projection expects, there will be intense competition between gas and residual fuel oil in the mid-1990s that can be addressed only by flexible pricing of gas to fuel-switching customers.

AVERAGE DELIVERED NATURAL GAS PRICES

(1987$ / MMBtu)



1988 GRI Baseline Projection

Average Delivered Natural Gas Prices

(Slide 10) This figure shows the projected trends in average delivered gas prices for residential customers and electric utilities. Because of the nature of the markets, these tend to be the highest and lowest energy price sectors respectively. The components attributable to the acquisition price and to transmission and distribution (or T&D) costs are also shown.

The residential T&D charge declines almost 5 percent by 1995, principally as a result of reduced transmission costs such as the resolution of take-or-pay pass-through and amortization of capital investment. The T&D charges begin to increase after 1995 as the result of new capital investments in infrastructure which are required and because of increased costs of pipeline fuel and gas storage resulting from higher gas acquisition prices.

T&D charges to electric utilities show a steady decline through the entire forecast period. Through 1995, the decline is a result of transmission cost factors. After 1995, because of competition from residual fuel oil, the full recovery of allowed rates of return to transmission and distribution companies cannot be realized in some markets, and the average price for T&D remains low.

The gas acquisition price for electric utilities is also expected to be consistently lower than the gas acquisition price for residential customers. In 1987, this difference was quite large. It was due to a combination of the summer-peaking nature of some utility gas purchases and the competitive spot market in 1987. As the "gas bubble" disappears, spot prices on an annual average basis will tend to approach contract prices. Seasonal fuel-switching strategies and the advantages of sophisticated contracting arrangements, however, will still provide utilities with a possibility of lower acquisition costs.

Conclusions

All of this discussion is based upon some assumptions about prices of gas and competing fuels. They are set forth in my prepared text, but I haven't time to read it to you.

In summary, the significant point of common interest to both the Canadian and U.S. gas industries is the realization of market potential, especially in the large U.S. market.

The most significant new market opportunities are associated with large capital, long-term investment decisions such as powerplants, cogeneration facilities, and commercial buildings.

The choice of fuels in these decisions will rest upon confidence of the decisionsmakers in the reliability of supply and stability of price over the life of the investment.

The Canadian and U.S. gas industries must instill that confidence in gas as a fuel choice--and then they must deliver.

ENHANCED OIL RECOVERY OUTLOOK

ECONOMIC PROSPECTS FOR EOR IN CANADA

PRESENTED BY:

J. SHERROLD MOORE

SENIOR VICE PRESIDENT, SOUTH REGION

AMOCO CANADA PETROLEUM COMPANY LTD.

CALGARY, ALBERTA

CANADA

AT THE SEVENTH ANNUAL CERI

INTERNATIONAL OIL AND GAS MARKETS CONFERENCE

SEPTEMBER 18-20, 1988

CONVENTION CENTRE

CALGARY, ALBERTA

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CANADA

GOOD AFTERNOON LADIES AND GENTLEMEN. I'M VERY HAPPY TO BE HERE WITH YOU TODAY. AMOCO CANADA HAS BEEN INVOLVED IN EOR PROJECTS FOR OVER 20 YEARS AND HAS THE OLDEST CONTINUOUSLY OPERATED CONVENTIONAL OIL EOR PROJECT, THE ANTE CREEK MISCIBLE FLOOD, WHICH DATES BACK TO THE LATE 1960'S. WE ALSO HAVE BEEN TESTING A VARIETY OF HEAVY OIL EOR TECHNIQUES IN THE GREGOIRE LAKE AREA SINCE THE MID-1950'S.

AMOCO HAS CONTINUED TO BE A LEADER IN EOR TECHNOLOGY. WE NOW HAVE 15 CONVENTIONAL OIL EOR PROJECTS AND 9 HEAVY OIL EOR PROJECTS ON STREAM. TODAY SOME 35 PERCENT OF AMOCO'S CRUDE AND CONDENSATE RESERVES AND 20 PERCENT OF THE PRODUCTION IS ATTRIBUTED TO EOR PROJECTS. AMOCO OPERATES 16 PERCENT OF CANADA'S EOR

PROJECTS WHICH ENCOMPASS 28 PERCENT OF THE PROVINCIAL EOR RESERVES.

AMOCO CONTINUES TO SEE EOR ACTIVITY AS A KEY STRATEGIC UNIT IN OUR RESERVE DEVELOPMENT PLANS. THE REASON FOR THIS EMPHASIS IS DIRECTLY RELATED TO THE HIGH COST OF FINDING NEW RESERVES. THIS FACT ALONG WITH DECLINING RESERVE FORECASTS FROM KNOWN RESERVOIRS HAS ENCOURAGED APPLICATION OF NEW TECHNOLOGY WITH INCREASED EMPHASIS ON IMPROVING THE RECOVERY LEVEL FROM EXISTING FIELDS.

SEVERAL STUDIES HAVE BEEN CONDUCTED ON THE POTENTIAL FOR EOR IN CANADA SUCH AS THE NATIONAL PETROLEUM COUNCIL AND THE CANADIAN RESEARCH INSTITUTE ESTIMATE THAT THE APPLICATION OF CONVENTIONAL OIL EOR PROJECTS IN EXISTING RESERVOIRS COULD ADD RESERVES OF BETWEEN 0.7 AND 3.0 BILLION BARRELS. THIS POTENTIAL FOR RESERVE ADDITIONS IS SMALL IN ABSOLUTE TERMS, BUT QUITE SIGNIFICANT RELATIVE TO THE REMAINING RESERVES OF 5.1 BILLION BARRELS OF CONVENTIONAL OIL IN CANADA. THE POTENTIAL FOR RESERVE ADDITIONS, IF ONE CONSIDERS HEAVY OIL, IS SIGNIFICANTLY GREATER. WHILE IT IS DIFFICULT AT THIS TIME TO PREDICT HEAVY OIL RECOVERY FACTORS, IT IS ESTIMATED THE HEAVY OIL EOR RESERVE ADDITIONS COULD APPROACH 25 BILLION BARRELS.

THE TRANSLATION OF EOR PROCESSES FROM THE LABORATORY TO THE FIELD HAS ACCELERATED OVER THE LAST HALF A DOZEN YEARS WITH SOME 850 MILLION BARRELS OF CONVENTIONAL OIL RESERVES ADDED TO DATE THROUGH THE EXISTENCE OF SOME 50 PROJECTS. WHEN OTHER EOR PROCESSES, SUCH AS THERMAL PROJECTS AND CHEMICAL FLOODS, ARE INCLUDED THE NUMBERS ARE SIGNIFICANTLY HIGHER.

THE CRUDE PRICE DROP IN 1986 HAD ITS EFFECT ON ALL EOR PROJECTS; HOWEVER, WE CONTINUE TO SEE SOME APPLICATION OF BOTH POLYMER AND MISCIBLE FLOOD PROJECTS WHERE SPECIFIC RESERVOIR CHARACTERISTICS AND OTHER CIRCUMSTANCES PROVIDE THE NECESSARY INCENTIVES. AS DISCUSSED LATER, THE BACKDROP NECESSARY TO RE-ACTIVATE EOR PLANS INCLUDES HIGHER STABILIZED OIL PRICES COUPLED WITH GOVERNMENT LEGISLATION THAT PROVIDES THE NEEDED FISCAL ENVIRONMENT.

BOTH THE U.S. AND CANADA HAVE ACTIVELY PURSUED CONVENTIONAL OIL EOR PROCESSES AS ONE OF THE SHORT TERM ANSWERS TO OUR FUTURE ENERGY REQUIREMENTS. THE TECHNOLOGY SHARED BETWEEN THE TWO COUNTRIES HAS RESULTED IN THE IMPLEMENTATION OF MANY PROJECTS, WITH THE ONLY MAJOR DIFFERENCE BEING THE TYPE OF SOLVENT EMPLOYED. THE U.S. OPERATIONS ARE ALMOST EXCLUSIVELY BASED UPON CARBON DIOXIDE, THE CANADIAN PROJECTS ALMOST

EXCLUSIVELY USE ENRICHED HYDROCARBON GAS. THE CHOICE BETWEEN THE TWO TYPES OF SOLVENT FOR FUTURE PROJECTS WILL DEPEND LARGELY UPON THE SAME CRITERIA WHICH DICTATED THEIR USE IN THE PAST: THAT IS RELATIVE COSTS AND AVAILABILITY.

BUT, ALTHOUGH SOME DIFFERENCES MAY EXIST BETWEEN THE EOR PROCESS IN CANADA AND THE UNITED STATES, THE CHALLENGES FACED BY BOTH COUNTRIES ARE CONSISTENT. FOREMOST AMONG THESE CHALLENGES IS THE MANAGEMENT ATTITUDE THESE HIGHLY TECHNICAL PROJECTS HAVE COMMANDED. THE MOVE TOWARDS EOR PROJECTS HAS NECESSITATED A DIFFERENT APPROACH TOWARD PROJECT MANAGEMENT AND IMPLEMENTATION THAN WAS SEEN IN THE WATERFLOODS CURRENTLY IN OPERATION. IT'S LIKE COMPARING THE NEW CARS ON THE ROAD TODAY, WITH THEIR COMPUTER REGULATED FUEL AND IGNITION SYSTEMS, WITH THE OLD MODEL T. TO KEEP THE NEW CARS OF TODAY RUNNING SMOOTHLY YOU REQUIRE A TEAM OF EXPERTS WHO ARE FULLY TRAINED TO SOLVE A VARIETY OF PROBLEMS.

IN CANADA, A LARGE NUMBER OF GOOD QUALITY RESERVOIRS ARE EITHER UNDER MISCIBLE FLOOD OR ARE IN THE APPROVAL STAGES. THE REMAINING CROP CONSISTS OF LOW PRODUCTIVITY AND VERY LOW RECOVERY LEVEL RESERVOIRS. AS THE SECOND GENERATION OF EOR CANDIDATES, THESE

FIELDS WILL PRESENT AN EVEN GREATER CHALLENGE THAN THE CURRENT PROJECTS.

THE PEMBINA CARDIUM FIELD IN WEST CENTRAL ALBERTA IS TYPICAL OF THIS SECOND GENERATION. ORIGINAL OIL IN PLACE OF APPROXIMATELY 7 BILLION BARRELS WITH A VERY LOW RECOVERY OF 25 PERCENT UNDER WATERFLOOD, LOW PERMEABILITIES IN THE RANGE OF 1-15 MD, AND A RESULTING LOW PRODUCING RATE. AMOCO CANADA IS IN THE PROCESS OF PROVING UP THE TECHNOLOGY NECESSARY TO DEVELOP THIS RESOURCE AND INTENDS TO SPEND THE $25 MM NECESSARY FOR A PILOT OVER TWO SECTIONS TO PROVE THE TECHNOLOGY TO THE REGULATORY BODIES.

IN CANADA, THE EXISTING GOVERNMENT REGULATIONS DO NOT ADEQUATELY COVER THESE LOW PERMEABILITY RESERVOIRS FROM A FISCAL POLICY STANDPOINT, AND IT IS OUR INTENTION TO USE THIS PILOT TO PROVE UP THE TECHNOLOGY AND PUT IN PLACE, THROUGH NEGOTIATIONS WITH THE GOVERNMENT, A FISCAL REGIME THAT WILL ALLOW THESE PROJECTS TO PROCEED. IN ALBERTA, THE GOVERNMENT HAS IN PLACE A FISCAL POLICY THAT PROVIDES THE OPERATOR WITH ROYALTY CREDITS IN A MISCIBLE FLOOD THAT OFFSETS THE CROWN SHARE OF INCREMENTAL COSTS OF MISCIBLE OVER WATERFLOOD. THIS POLICY DOES NOT WORK WITH LOWER PRODUCTIVITY

RESERVOIRS BECAUSE OF THE SLIDING SCALE ROYALTY SCHEDULE IN EFFECT.

FOR EOR PROJECTS TO PROCEED IN A TIMELY MANNER THE GOVERNMENT POLICIES DEALING WITH FISCAL REGIMES SUCH AS TAXES, ROYALTIES, AND INCENTIVES MUST BE FAIR, EQUITABLE AND ABOVE ALL STABLE IN ORDER FOR THESE PROJECTS TO FLOURISH. IN THE PAST IN CANADA AS WELL AS IN THE U.S. ROUGHLY PARALLEL PATHS HAVE BEEN FOLLOWED; A SHARP RISE IN GOVERNMENT LEVIES TRIGGERED BY THE INCREASE IN OIL PRICE FOLLOWED BY SELECTIVE REDUCTION IN THE TAX LEVELS LINKED TO PROGRAMS DEEMED DESIRABLE BY THE GOVERNMENT AND ACCOMPANIED BY A HOST OF RULES AND REGULATIONS. WHAT IS REQUIRED IS LEGISLATION THAT PUTS IN PLACE A STABLE FISCAL REGIME WHICH WILL ALLOW THE INDUSTRY TO GET ON WITH THE REPLACEMENT OF A DEPLETING RESOURCE AND SUSTAIN THE PRODUCTION LEVELS NECESSARY TO MAKE BOTH COUNTRIES LESS DEPENDENT ON IMPORTED OIL.

CANADA IS FORTUNATE IN THAT IT HAS OVER 2 TRILLION BARRELS OF OIL LOCKED UP IN THE HEAVY OIL DEPOSITS AND OIL SANDS OF ALBERTA. AS WE LOOK TO THE FUTURE, CONVENTIONAL OIL EOR PROCESSES ARE AT A MATURE STAGE AND WILL PROVIDE A BRIDGE UNTIL ECONOMICS SUPPORT HEAVY OIL DEVELOPMENT. THE QUESTION FOR DEVELOPMENT OF HEAVY

OIL RESOURCES IS NOT IF BUT WHEN. TECHNOLOGICAL ADVANCEMENTS ARE EXPECTED TO MAKE HEAVY OIL PROJECTS MORE ECONOMICALLY ATTRACTIVE IN THE EARLY 1990'S. IT IS FORECAST THAT EXISTING CONVENTIONAL LIGHT AND MEDIUM CRUDE PRODUCTION WILL DECLINE BY 50 PERCENT FROM 850 000 BPD TO LESS THAN 400 000 BPD BY THE YEAR 2000. CONVENTIONAL HEAVY OIL AND BITUMEN PRODUCTION WILL RISE BY 140 PERCENT TO 500 000 BPD, BUT WILL ONLY REPLACE 50 PERCENT OF THE DECLINE OF CONVENTIONAL CRUDE.

HEAVY OIL WILL BECOME A MAJOR CONTRIBUTOR TO THE FUTURE OF ALBERTA'S OIL INDUSTRY. TO ACHIEVE THIS WILL REQUIRE A QUANTUM LEAP FORWARD IN TECHNOLOGY. AS YOU KNOW, AS THE API GRAVITY DECREASES AND THE VISCOSITY INCREASES, THE PROBLEMS INCREASE. CURRENT INSITU COMMERCIAL HEAVY OIL PROJECTS ARE CONFINED TO RESERVOIRS THAT HAVE MOBILE OIL IN THEM AT EXISTING RESERVOIR TEMPERATURES AND PRESSURES. WITH THE ADDITION OF HEAT, THESE RESERVOIRS BECOME PRODUCIBLE AT COMMERCIAL RATES.

AS WITH CONVENTIONAL OIL EOR PROJECTS, EACH HEAVY OIL RESERVOIR HAS ITS OWN UNIQUE PROBLEMS REQUIRING THE SKILLS AND EXPERTISE OF A MULTI-DISCIPLINED TEAM. PROCESS DESIGN INVOLVES THE SELECTION OF VARIOUS RECOVERY MECHANISMS, ALL OF WHICH, HAVE ONE THING IN

COMMON: THE INTRODUCTION OF HEAT INTO THE RESERVOIR TO REDUCE THE VISCOSITY OF THE OIL AND PROVIDE ENERGY FOR FLOW TOWARDS THE WELLBORE.

AS WITH CONVENTIONAL OIL EOR PROJECTS TODAY, HEAVY OIL EOR PROJECTS WILL GAIN MORE SIGNIFICANCE IN THE FUTURE AS MORE OF THE MAJOR FIELDS ARE CONVERTED TO EOR.

OF THE REMAINING MAJOR FIELDS WHICH AMOCO WOULD LIKE TO PLACE UNDER EOR IN ALBERTA, DOME PETROLEUM WAS OUR MAJOR PARTNER. WE RECOGNIZED THAT DOME AND AMOCO HAD A LOT IN COMMON. IN ADDITION TO BEING PARTNERS WITH THEM IN OVER 100 PROPERTIES WE ALSO WERE EQUAL PARTNERS IN THE NGL BUSINESS. THIS INVOLVES THE PURCHASE AND PRODUCTION OF NGLS FROM THE GAS PLANTS THROUGHOUT WESTERN CANADA, THE TRANSPORTATION OF THESE PRODUCTS TO EASTERN CANADA AND THE FRACTIONATION AND SALE TO EASTERN MARKETS IN THE U.S. AND CANADA.

AMOCO REALIZED AN ACQUISITION OF DOME WOULD EXPEDITE OUR PLANS FOR EOR DEVELOPMENT ON THE JOINTLY HELD PROPERTIES. WE ASSEMBLED A GROUP OF ENGINEERS AND ECONOMISTS TO EVALUATE THE COMPANY AND ON APRIL 18, 1987, WE WERE THE SUCCESSFUL BIDDER FOR DOME. SINCE THEN, WE HAVE DEVOTED AN EXTRAORDINARY AMOUNT OF TIME

AND EFFORT TO COMPLETE THE ACQUISITION. TODAY WE ARE ONE COMPANY.

THE NEW AMOCO CANADA WILL BE THE NUMBER ONE PRODUCTION COMPANY IN CANADA WITH OVER 240 000 BBL/D IN BARRELS OF OIL EQUIVALENT PRODUCTION. WE WILL BE A VERY ACTIVE COMPANY WITH EXPENDITURES ON CAPITAL PROJECTS OVER THE NEXT FIVE YEARS ESTIMATED TO TOTAL $2.5 BILLION DOLLARS WHICH IS OVER $1 BILLION MORE THAN BOTH COMPANIES WOULD HAVE SPENT SEPARATELY. OF DIRECT INTEREST TO THIS GROUP, AT LEAST $100 MILLION WILL GO TOWARD RESEARCH AND DEVELOPMENT, OF WHICH CONVENTIONAL AND HEAVY OIL EOR RESEARCH WILL ACCOUNT FOR 75 PERCENT.

AMOCO HAS IDENTIFIED A NUMBER OF ATTRACTIVE OPPORTUNITIES FOR INVESTMENT IN CANADA. TEN PROPERTIES HAVE BEEN IDENTIFIED FOR IMPLEMENTATION OR EXPANSION OF WATERFLOODS. FORTY-FIVE PROPERTIES HAVE BEEN IDENTIFIED FOR DEVELOPMENT DRILLING PROGRAMS, AND TWO MAJOR PROPERTIES HAVE BEEN IDENTIFIED FOR EOR. FURTHERMORE, WE HAVE PLANS TO REACTIVATE OUR HEAVY OIL PILOT PROJECT ON THE PRIMROSE ACREAGE AND TO BEGIN CONSTRUCTION ON THE FIRST PHASE OF THE COMMERCIAL PROJECT. THE FIRST PHASE OF THE PROJECT WILL HAVE PRODUCTION LEVELS OF 10 000 BOPD. AND, OF COURSE, AS

ECONOMICS IMPROVE OTHER MAJOR PROJECTS WILL BE INITIATED ON DOME AND AMOCO ACREAGE.

THE MANAGEMENT CHALLENGES AMOCO FACES IN CANADA IN THE NEXT FEW YEARS ARE MATCHED ONLY BY THE CHALLENGES WE ONCE FACED WHEN WE STARTED OUR OPERATIONS HERE 40 YEARS AGO. THEY ARE CHALLENGES THAT AMOCO EAGERLY ACCEPTS. OUR TECHNOLOGICAL ABILITIES WILL BE SEVERELY TESTED AND I AM SURE OUR FUTURE WILL BE AS SUCCESSFUL AS OUR PAST.

WE REALIZE CONVENTIONAL OIL EOR PROJECTS ARE, IN A CERTAIN SENSE, A BRIDGE TO AUGMENT SUPPLIES WHILE HEAVY OIL AND FRONTIER DEVELOPMENTS ARE BEING BROUGHT ON STREAM.

WE CAN MAKE SEVERAL CONCLUSIONS FROM THIS BRIEF EXAMINATION OF THE ECONOMIC PROSPECTS FOR EOR.

WE MUST REALIZE THAT EOR WILL NOT BE A DRAMATIC 8000 BARREL PER DAY FRONTIER DEVELOPMENT NOR WILL IT BE A $6 BILLION MEGA PROJECT THAT WILL PRODUCE 150 000 BARRELS PER DAY. IT WILL BE MANY SMALL PROJECTS SPREAD ACROSS THE WESTERN CANADIAN SEDIMENTARY BASIN THAT WILL CONTRIBUTE TO INCREASING RESERVES.

THE PROSPECT FOR CONVENTIONAL OIL EOR REPRESENTS ALMOST A 3 BILLION BARREL POTENTIAL SUPPLY OF GOOD QUALITY CRUDE THAT IS READILY ACCESSIBLE, WITH WELLS AND PIPELINES IN PLACE. THE POTENTIAL FOR HEAVY OIL EOR IS MUCH GREATER.

DEVELOPMENT OF EOR RESOURCES WILL NOT BE CONSTRAINED BY LIMITED CAPITAL OR THE CHALLENGES OF THE FRONTIERS, IT CAN BE TACKLED AS A NUMBER OF SMALL PROJECTS.

I AM PLEASED WITH THE PROGRESS OF ENHANCED OIL RECOVERY PROCESSES DURING THE LAST SEVERAL YEARS AND I AM CONFIDENT IN ITS FUTURE. AMOCO CANADA WILL BE LOOKING TOWARD EOR TO PLAY A SIGNIFICANT ROLE IN THE GROWTH OF THE COMBINED AMOCO-DOME COMPANY IN THE NEAR FUTURE.

THE ECONOMIC PROSPECTS FOR EOR OVER THE NEXT FEW YEARS IN CANADA PROMISES TO BE A CHALLENGE AND THE MOOD SHOULD BE ONE OF OPTIMISM.

THANK YOU.

ENHANCED OIL RECOVERY OUTLOOK

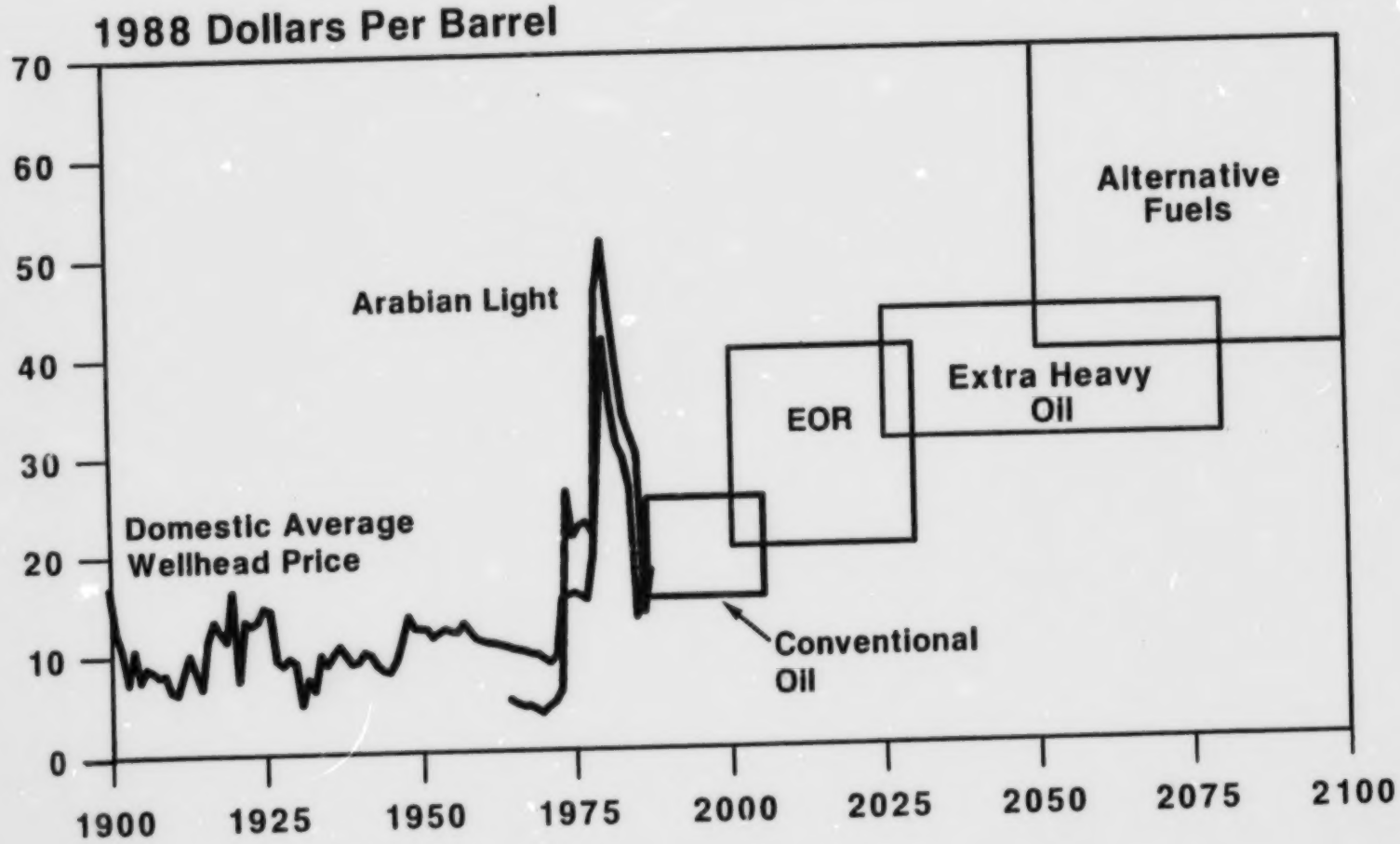
Presented by

Tom Burns
Manager, Economics
Corporate Planning and Analysis
Chevron Corporation
San Francisco, California

At
The Seventh Annual CERI
International Oil and Gas Markets Conference
September 18-20, 1988

Convention Centre
Calgary, Alberta

Crude Price Outlook



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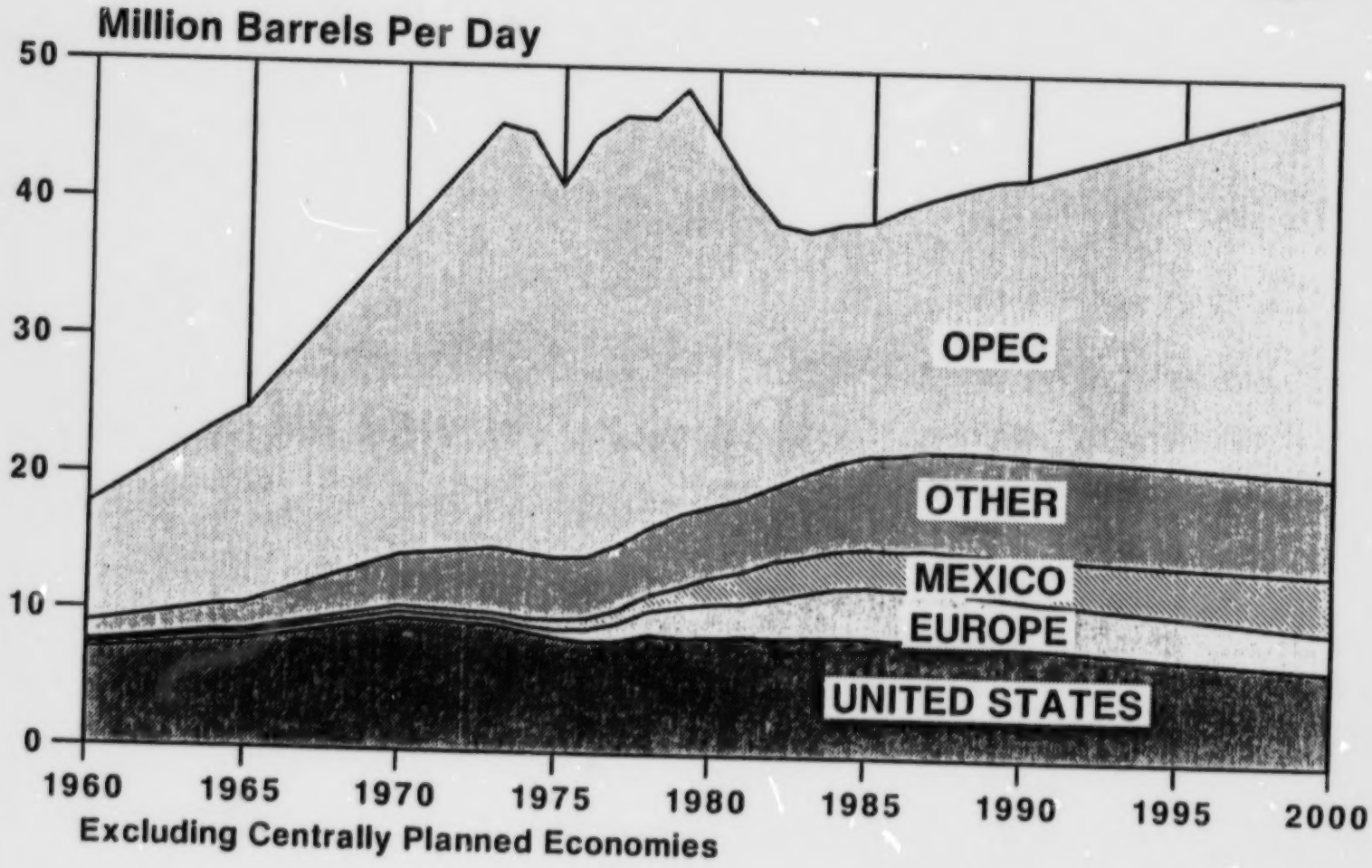
Crude Oil Production



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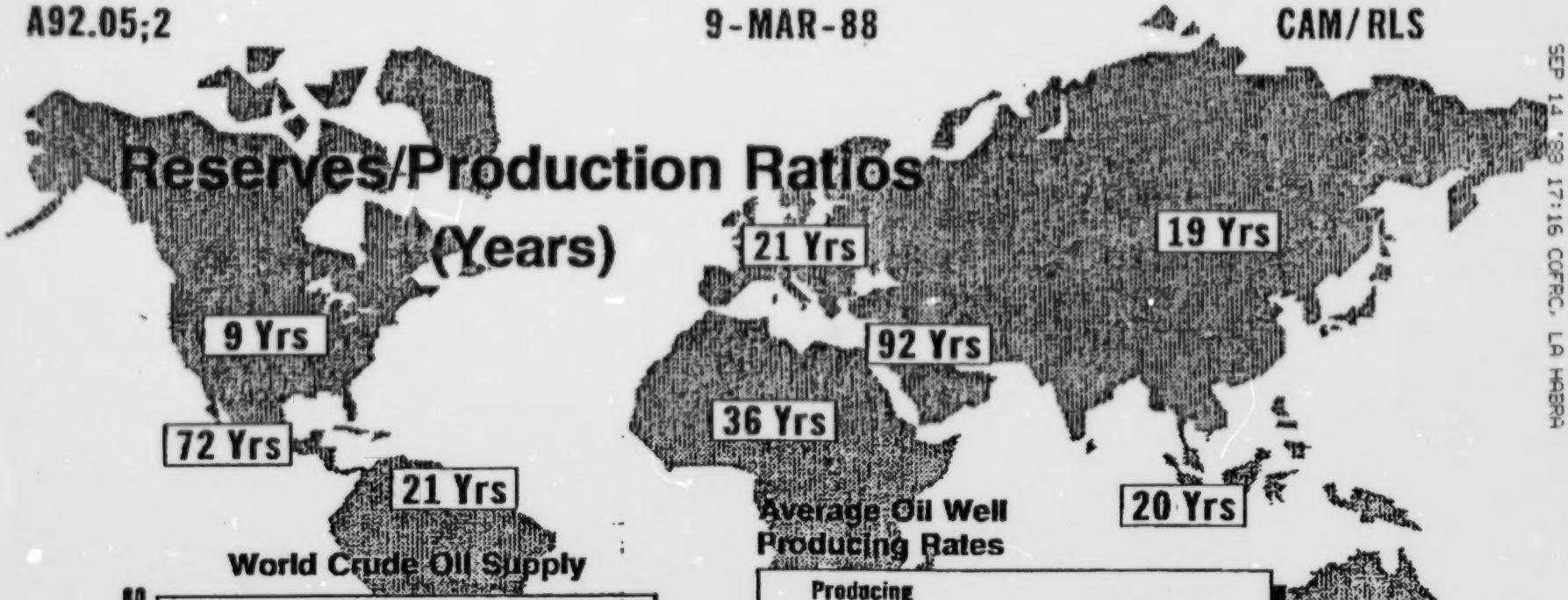
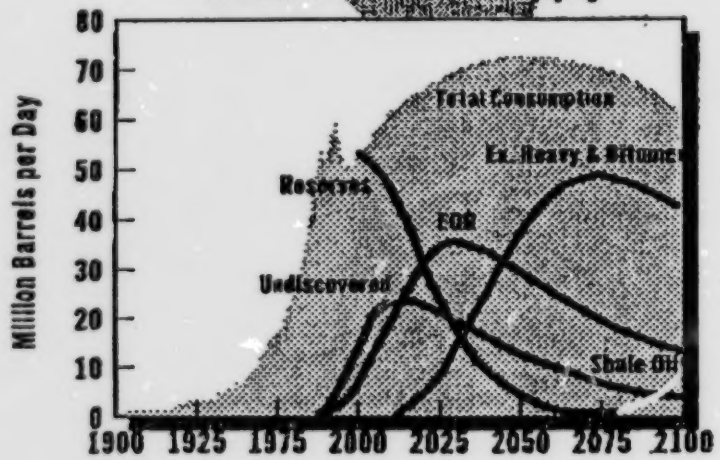
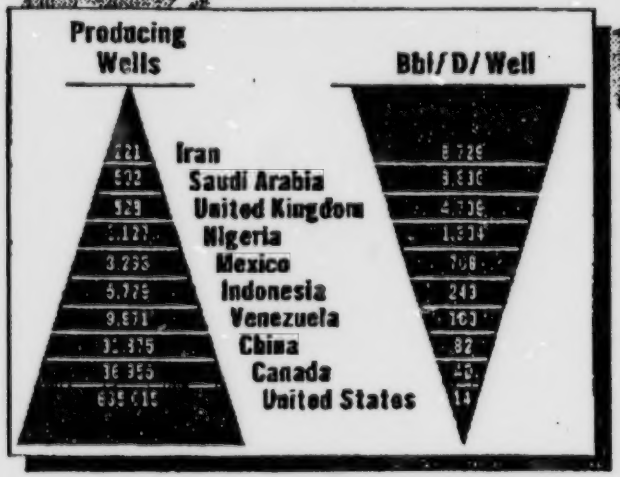
Reserves/Production Ratios (Years)



World Crude Oil Supply

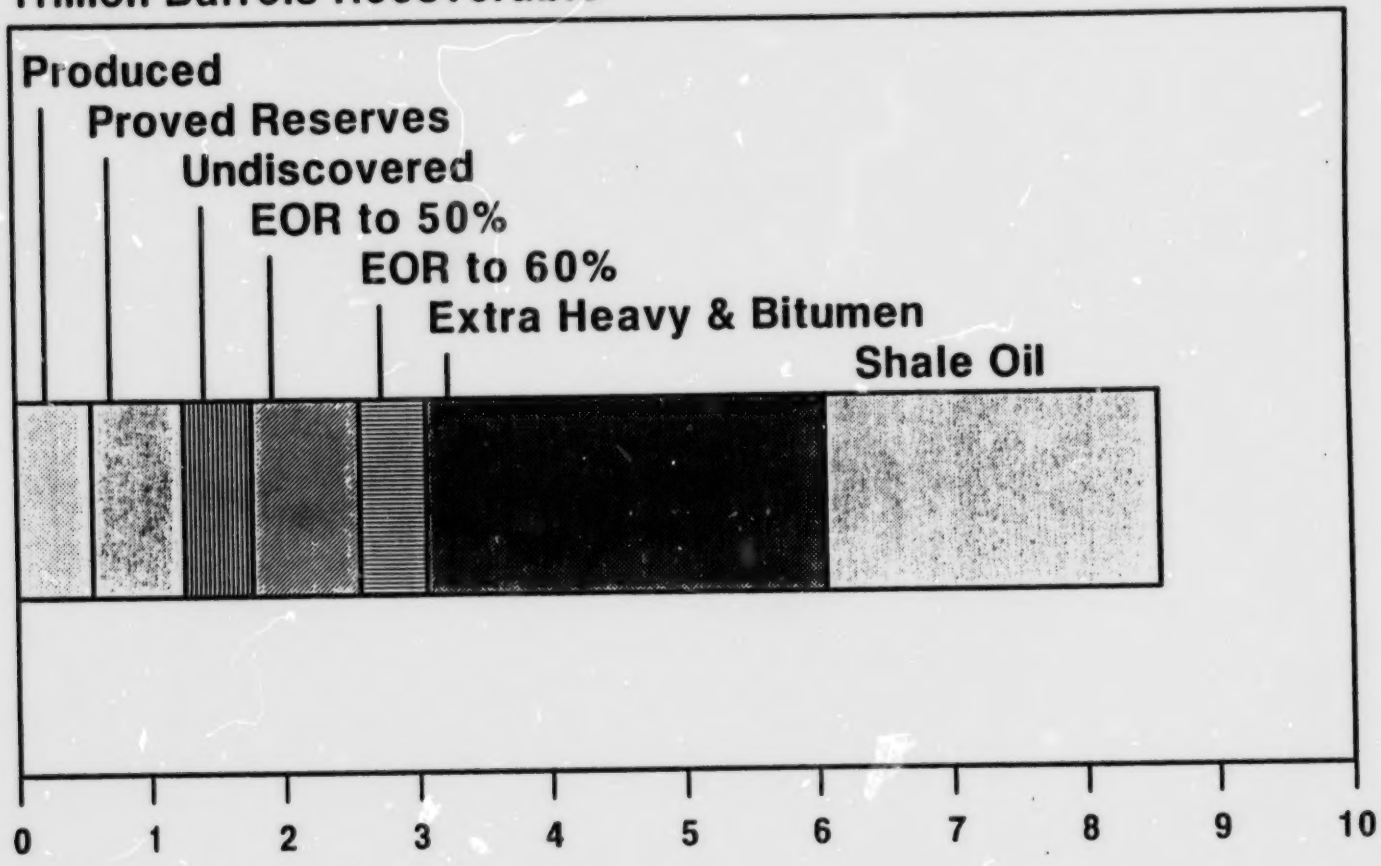


Average Oil Well Producing Rates



Estimated Resource Base

Trillion Barrels Recoverable



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Oil Recovery Methods

PRIMARY RECOVERY

Natural Flow

Artificial Lift
(Pump, Gas Lift, etc.)

SECONDARY RECOVERY (Enhanced)

Waterflood

Infill Drilling

Pressure Maintenance
(Water, Gas Reinjection)

TERTIARY RECOVERY (Enhanced)

Thermal
(Cyclic Stimulation, Steamflooding, In Situ Combustion)

Gas
(Cyclic CO_2, CO_2 Miscible, Nitrogen, Immiscible Gas, Hydrocarbon Miscible)

Chemical
(Polymer, Micellar/Polymer, Alkaline)

Microbial
(Cyclic Microbial, Microbial Flooding)

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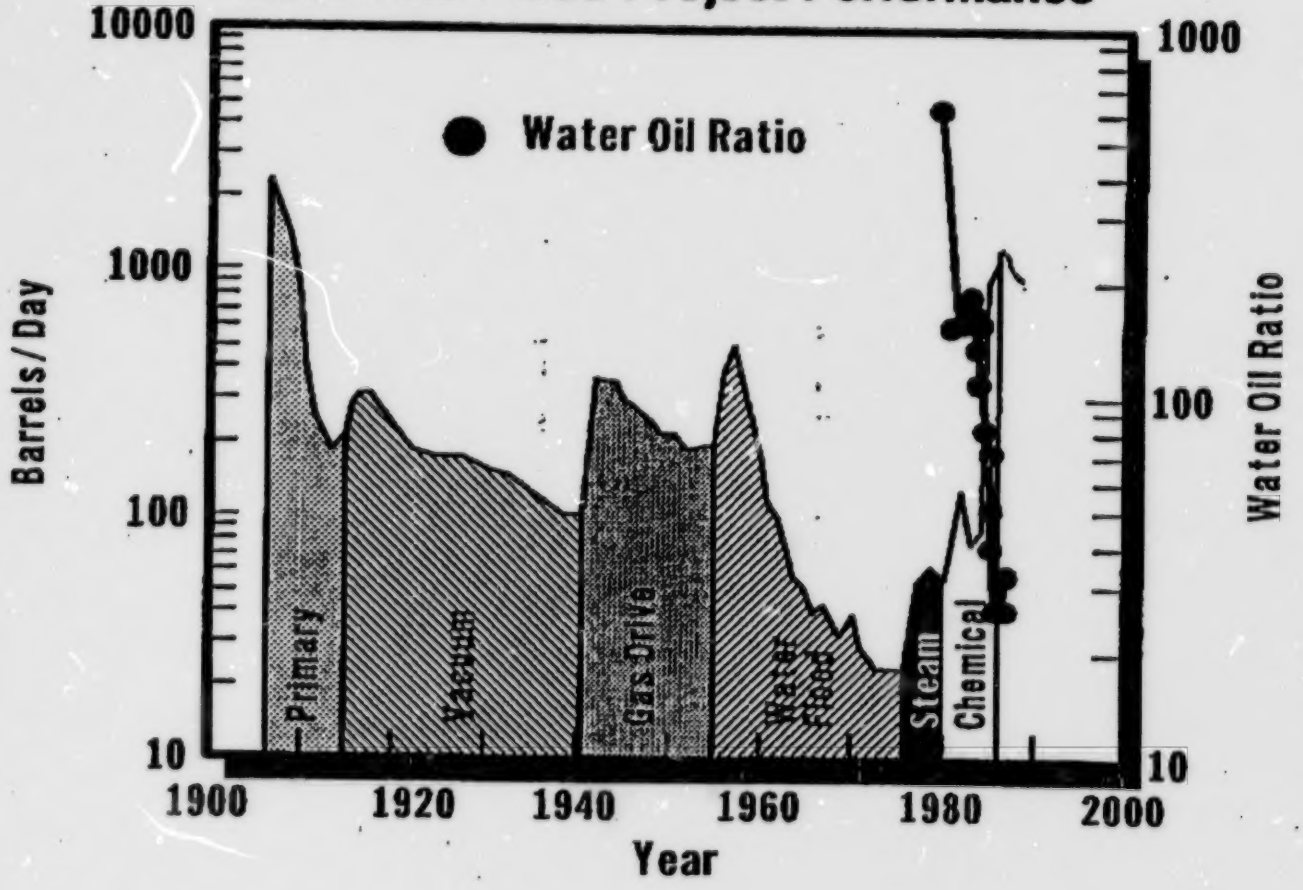
Production History

Chemical Flood Project Performance



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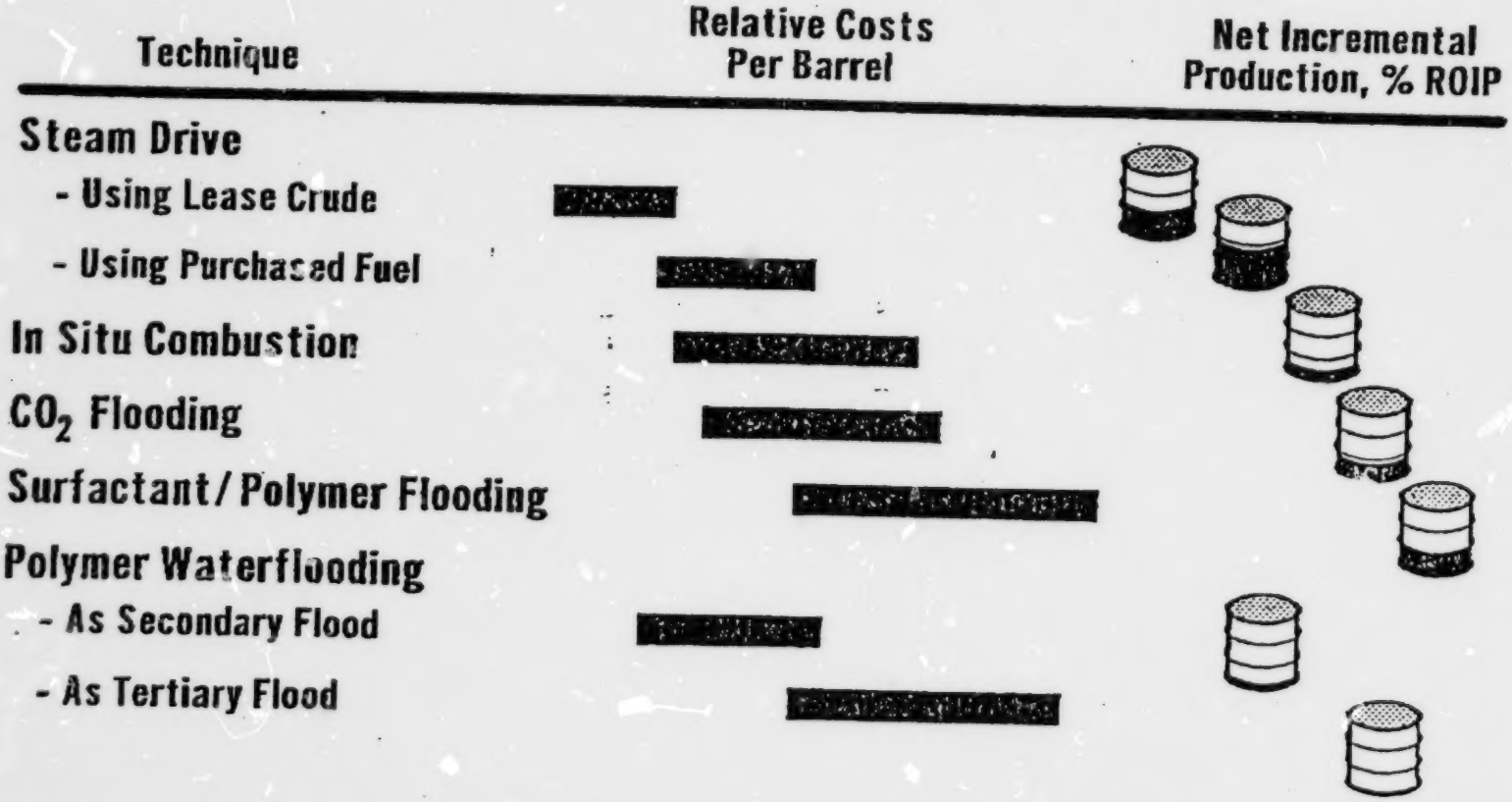
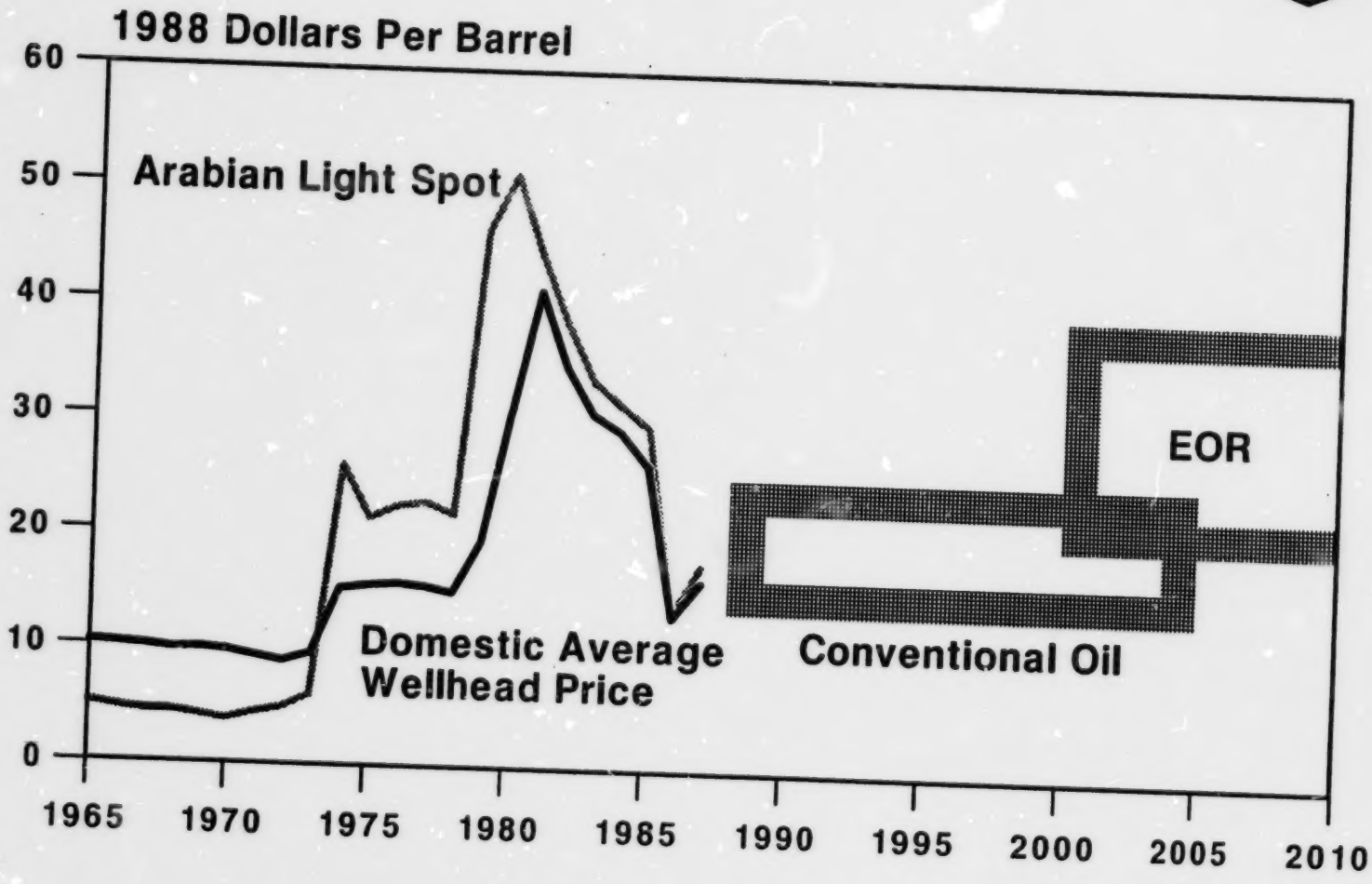
EOR Cost Range & Recovery Efficiency



Crude Price Outlook



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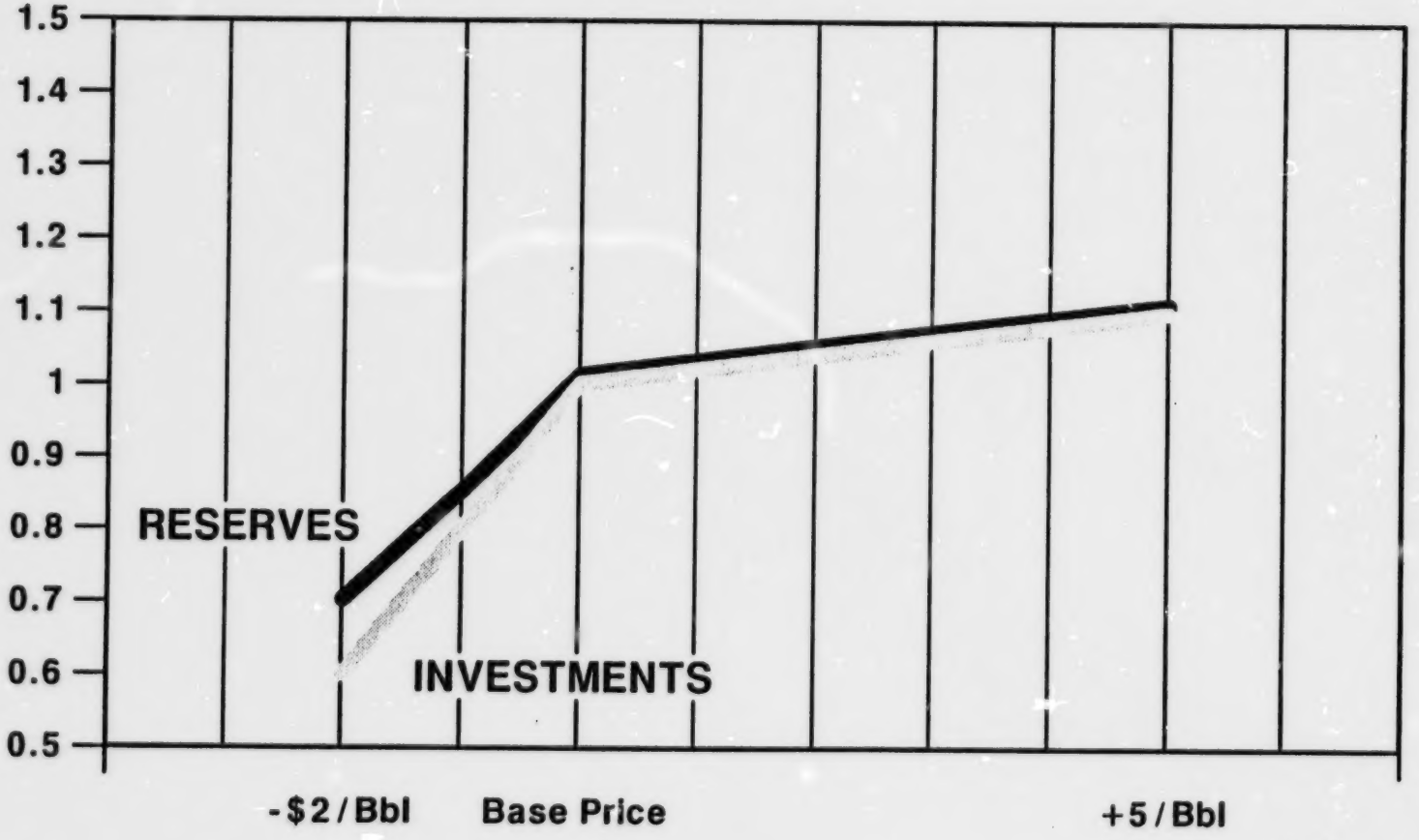
California Steam Drive Program

Price Sensitivity (Base Program = 1.0)



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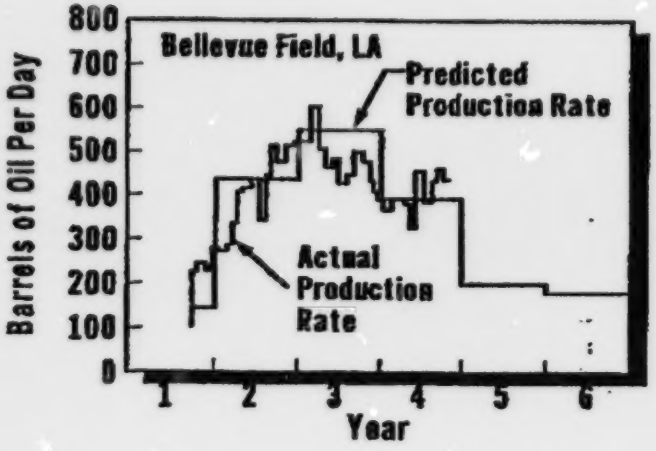
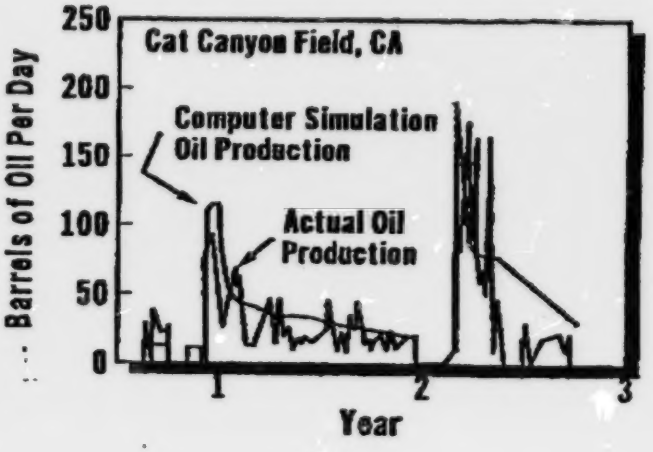
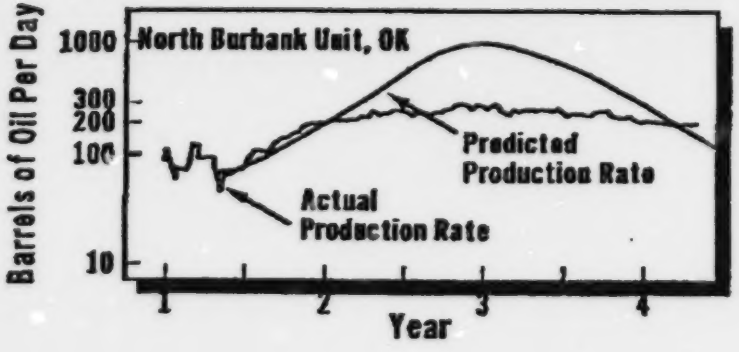
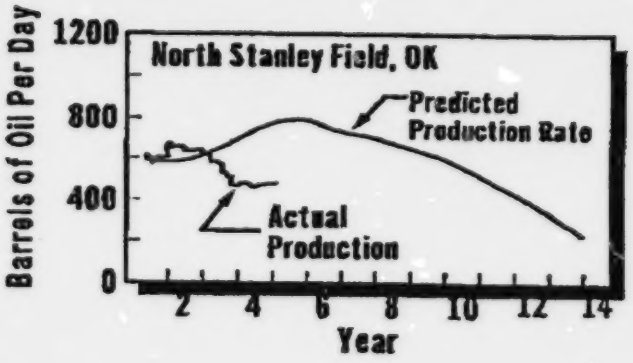
Enhanced Recovery Projects Have Often Failed To Perform as Predicted in Actual Field Settings









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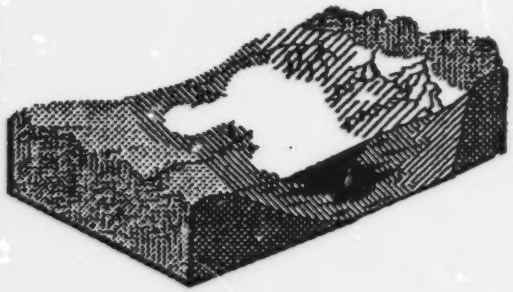
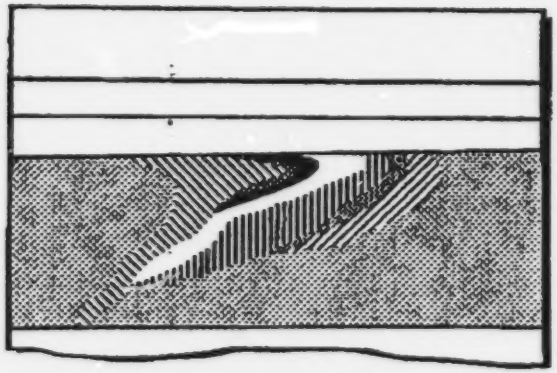
Reservoir Characterization

An Integrated Overview

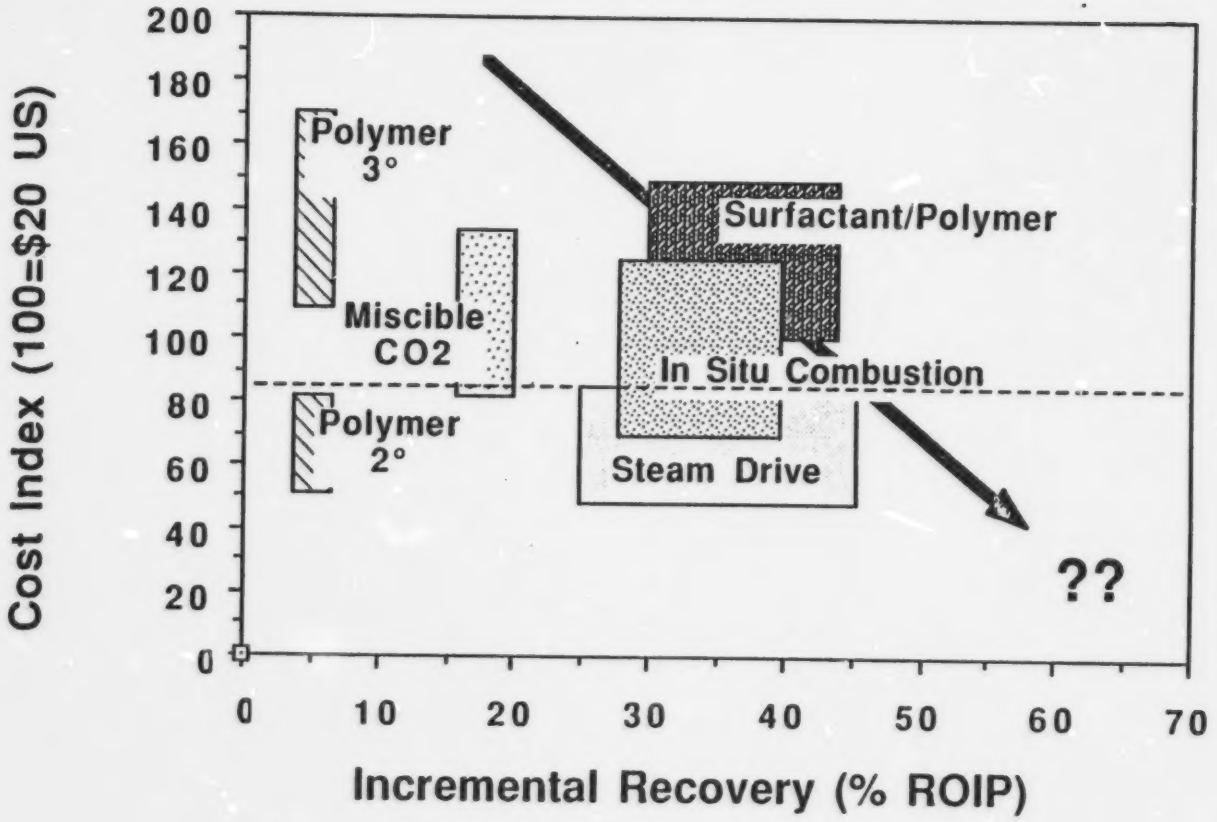
Geologic Model



Fluid Flow Model



Cost & Performance of EOR



Thermal Recovery Research Issues

Inexpensive Heat
- BTU's in the Reservoir
- Steam Quality Measurements & Distribution

Reservoir Characterization
- Permeability from Logs
- Lithology from Logs
- Reservoir Properties at T, P
- Fractured Reservoirs

Field Process Monitoring
- Tomography
- Cased Hole Logs
- Areal & Vertical Sweep

Process Mechanisms
- Optimize Operations
- Steam Rock Reactions
- Fluid Flow Properties at T, P
- Surface Chemistry

ENHANCED OIL RECOVERY

A NORTH SEA PERSPECTIVE

Presented by

Peter A Parris

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At
The Seventh Annual CERI
International Oil and Gas Markets Conference
September 18-20 1988
Convention Centre
Calgary, Alberta

RESERVOIR CHARACTERISTICS

North Sea oil fields can generally be classified as high permeability sandstone reservoirs containing low viscosity oil. They exhibit very high production rates and a favourable water to oil mobility ratio gives good sweep efficiency to waterflooding. This has resulted in field developments having large well spacings with pressure support by water injection from production start-up.

In most reservoirs the oil is undersaturated and pressures, temperatures and salinities are high. A general range of reservoir and fluid characteristics is given in Table 1.

PRODUCTION CHARACTERISTICS

Much of the North Sea oil production is from water depths of 250 to 400 feet. Optimum field development has been achieved by combining high angled drilling from a minimum number of costly fixed platform locations and subsea tie-ins for "out of reach" well locations. This results in a high front-end capital cost and virtually fixed production facilities at the initial design phase when limited reservoir data is available from a few appraisal wells. The high capital cost is offset by rapid production usually reaching plateau within one year of start-up.

The majority of fields have little pressure support from natural water influx. The good sand quality and favourable water-to-oil mobility ratio results in high well flows (10-30 mbpd per well) and excellent sweep efficiency to waterflood. Recovery factors of 45-65% are obtained with residual oil saturations between 15-30% in the water swept regions of the reservoir.

Enhanced recovery, in North Sea terms, therefore means improving the water flood efficiency or targeting oil trapped in waterflooded regions. The former will need to be undertaken early on in field production to give maximum benefit. The latter could, in theory at least, be carried out after waterflood (i.e. in a normally termed tertiary phase). It is clear however that tertiary application either by chemical or gas injection will involve a considerable time delay from EOR field injection to incremental oil production. With North Sea well spacings this is typically 2 to 3 years. This in itself is difficult for a project to support as well productivities are likely to be less than the earlier waterflood development. In addition the project must bear the costs of keeping the offshore installation operable during this delay in income. On this basis tertiary application would only be economic in exceptional circumstances.

It is clear therefore that EOR operations must take place early enough in field life that conventional oil recovery will pay for the platform operating costs. To facilitate this and avoid expensive retrofitting to the platform in the offshore environment EOR potential needs to be considered in the initial design phase. There lies the classic dilemma for EOR application offshore. Good reservoir description based on dynamic field measurement is essential for EOR planning but not available at the this initial project development stage.

RESERVES AND EOR POTENTIAL ON THE UKCS

The UKCS production profile Figure 1, shows a major decline in oil production through the next decade, even allowing for probable and possible reserves development.

Allowing for an oil price stability around $15-20 per barrel a contribution to oil production from EOR techniques is possible. A technical potential of 750 to 2200 mmbbl of oil has been reported (1). This amounts to some 3-5% of reserves in

place. Taking a pessimistic view of oil price and assuming only 10% of these reserves are then likely to be recovered, still results in incremental recovery between 75 and 220 mmbbls. The economic lifetime of most of these mature fields dictate that EOR must start around 1995 if any of this reserve potential is to be realised.

At the current oil price the only EOR processes that look favourable in an offshore environment are polymer and some gas applications. It will take an oil price in excess of $20 per barrel before surfactants start to show potential. Minimum oil price ranges for the various EOR techniques are given in Table 2.

RESERVOIR CHARACTERISATION

The success or failure of an EOR application is largely dependent on good reservoir description. It is essential to have an adequate geological model, an understanding of the rock mineralogy, the physical and chemical conditions within the reservoir and, above all where the target oil is situated. Clearly this detail needed to accurately plan an EOR application is not available at the initial field development stage. Yet, if it is not considered, later expensive retrofitting of EOR facilities on a platform may well kill a project that is probably at best marginal.

What is the solution? Clearly EOR potential will only be realised if adequate resources are devoted to its evaluation. A comprehensive screening process is essential at an early stage. If there is potential it should be considered at the design phase. It is unlikely that current more marginal field development will sustain speculative equipment investment but space planning and designing in potential future retrofit may well be a viable option. A pilot operation from a floating production facility could well minimise future risk but in an offshore environment this operation would be as large as a marginal field development and would have to be considered economically viable, in its own right.

The optimum timing for an EOR project will be just after plateau production. Sufficient production history will be available to provide adequate modelling data and accelerated incremental oil production will make the economics more robust. Earlier work (2) demonstrated that for a polymer injection project in a lower Brent (Jurassic) type reservoir facilities allowance and project start from beginning of field life results in an oil cost of $12/bbl whereas late implementation including retrofitting 7 years after start-up would be uneconomic at $20/bbl.

EOR strategy is equally as important. Consider a late surfactant injection scheme where dilute surfactant can be injected at 30 mbpd and oil produced at only 10 mbpd due to the need for artificial lift late in field life. Given an existing distribution of wells the more conventional inverted 5 spot flooding arrangements shown in Figure 2, has less producers to injectors than the pattern flood of Figure 3 and is therefore rate restricted. The pattern flood allows maximum injection well rates by having 3 producers to each injector and also better represents the flow paths in the reservoir. Figure 4 shows a dramatic acceleration of incremental oil by some 7 years, reducing the incremental oil costs from over $40 per barrel to $22 per barrel.

INFILL DRILLING

In all but large in area reservoirs the question of infill drilling, to obtain waterflood by-passed oil, is usually accommodated by good reservoir monitoring. Well rates are adjusted to optimise flow patterns in the reservoir or additional wells are drilled or side tracked as an on-going reservoir development. It is possible, however, that with a handful of large reservoirs the potential for a major infill drilling project may be contemplated, particularly when few spare well slots are available. Detailed geological knowledge and information on the whereabouts of residual oil is as essential to the evaluation of such a project as to EOR.

The use of a number of horizontal wells may be the optimum way of planning infill drilling in the future. The use of infill wells for EOR projects also needs serious consideration, particularly when planning EOR pilots in existing fields. Well to well distances of 2-3000 ft may not give an adequate response time to enable the full consequences of a pilot to be considered in time for a larger scale of application.

POLYMER FLOODING

Mobility ratios for North Sea reservoirs are generally favourable. However, in heterogeneous systems such as the Brent sands severe permeability contrasts in the Etive (Figure 5) can cause rapid water breakthrough and subsequent fluid handling problems, with associated oil production constraints. Water soluble polymers to reduce mobility or cross-linking polymers to block high permeability channels, can significantly reduce water cuts and sweep incremental oil from lower permeability regions.

Figure 6 shows the impact of a 600 ppm stable Xanthan solution inject over a two year period after an initial three years of waterflood. The flow mechanism for oil recovery is shown in a idealised form in Figure 7 (3). This cross flow effect of oil moving from the low to the high permeability layer in front of the polymer slug means that even with a degrading polymer having a half life of 6 months more than half of the incremental oil would still be produced. For this type of application polymer injection rates of between 2-5000 bpd would be typical, allowing for reduced injectivity of polymer solutions. Field requirements of around 500 to 1500 tonnes per annum of polymer would not be unrealistic. Target prices for Xanthan would need to be around $9000 per tonne including stability and injectivity chemical additives.

There are few reservoirs in the North Sea that have moderately viscous oil of 5-30 cP and active aquifers. It is possible to use polymer solutions to suppress the influx of a strong edge aquifer thus improving volumetric sweep. Figure 8 shows the mechanism in a radial segment model.

Key economic parameters for a polymer application are polymer loss mechanisms. These include retention, both mechanical entrapment and adsorption; thermal, chemical and microbial degradation; and shear degradation and injectivity losses. It is essential to fully evaluate these using reservoir fluids and rock material to provide data for reservoir simulation and economic analysis.

SURFACTANT FLOODING

Most onshore trials in surfactant flooding have utilised a concentrated slug of surfactants driven by a polymer solution. In an offshore environment this bulk handling and storage of chemicals is not possible. It is therefore necessary to use a dilute surfactant system that will be robust to the high temperature and salinity conditions encountered in North Sea reservoirs. This will require a tailored surfactant system much more costly than conventional petroleum sulphonates.

There is little doubt that a well designed surfactant system will recover most of the oil contacted. However, good system efficiency in an offshore reservoir development will only be achieved by reservoir planning and favourable geology. Large well spacings mean reservoir description can be questionable, unless sufficient production history is available, and give low pressure gradients which make oil mobilisation more difficult. In addition, uncertain knowledge of clay distributions can result in high surfactant loss due to adsorption.

Cost effective surfactant flooding in the North Sea will be dependent on a good understanding of phase behaviour that will result in interfacial tensions below 10^{-3}; adsorption at less than 0.5 mg/g; good reservoir description and efficient coupling of injector and producer wells into flooding patterns (the advantage of this has previously been described). Even with all of these parameters satisfied, it is most unlikely that application will be economic at oil prices below $20-25 per barrel.

GAS INJECTION

Gas injection offers the best opportunities for improved oil recovery in the North Sea. Gas injection, primarily for storage purposes, in the Brent, Ninian, Beryl and Fulmar reservoirs has demonstrated good sweep efficiency either through miscible, multi-contact miscible or immiscible gravity stable displacement. The high reservoir pressure, high permeabilities, high API-gravity oils and tilted strata provide very favourable conditions.

The economics for EOR recovery by these processes do, however, have a number of limiting factors. Hydrocarbon gas is generally committed to sales at high contracted prices. Deferred gas sales and late incremental oil recovery are significant economic hurdles to overcome. Additional gas compression and gas handling equipment in an offshore environment results in high front-end investment and the use of non-hydrocarbon gas such as nitrogen introduce reservoir engineering difficulties.

Assuming that hydrocarbon gas is too valuable and that no reservoirs of naturally occurring carbon dioxide are available, gravity stabilised nitrogen injection can technically recover substantial quantities of oil (5). The schematic diagrams (Figure 9) show the process. The pay-zone, flooded with injected or aquifer water, contains residual oil, typically 20-30% of the oil initially in place. If sufficient target oil is available and the process technically feasible the operation has potential in a tertiary phase although nitrogen production costs must be minimised. Table 3 shows target costs for nitrogen for an offshore tertiary project to achieve breakeven. These costs are based on oil production revenues and ignore tax implications.

A number of technical issues will need to be resolved including three-phase relative permeability, rate effects, reservoir heterogeneity, rock, wettability gas and water coning.

HEAVY OILS

There have been a number of North Sea discoveries which can be termed heavy oil. Those reported include the Bressay field and in the South Viking Graben, Block 9/12. Measured oil viscosities for these type of fields vary between 300 and more than 1000 CP. Often they are characterised by unconsolidated sands having high porosity and permeability, and strong natural aquifers. Water coning is therefore a serious problem.

Conventional techniques of heating the oil are extremely difficult in the offshore environment of the North Sea. Reservoir depths around 3-4000 ft are on the limit for enthalpy efficient steam application and oxygen injection for insitu combustion raises serious safety implications in the confined offshore location. In addition, economic offshore development generally dictates well spacings in excess of 100 acres. Experience of these processes is based on much lower well spacing. The high permeability sands also provide serious coning and gravity override problems with these techniques.

The economic development of these fields will require innovative thinking and will almost certainly combine techniques such as polymer gels and horizontal drilling.. To achieve acceptable recovery efficiencies oil prices in excess of $20 per barrel are necessary.

FISCAL POSITION

No specific tax incentives are given for EOR projects in the North Sea in either the Uk or Norway. Both countries allows tax relief on approved R&D spend, which can include EOR studies and both have stated that they are prepared to consider further tax incentives on incremental projects provided that clear tax obstacles on actual projects are presented by the oil industry. Tax incentives will be necessary to encourage EOR projects, particularly if the oil price remains below $20 per barrel.

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5. BATH P G H, van der BURGH J, YPMA J G J, "Enhanced Oil Recovery in the North Sea" World Petroleum Congress London 1983

TABLE 1

Typical Reservoir and Fluid Characteristics
in North Sea Oil Fields

Pressures	8000-10,000 psi
Temperatures	90 - 120°
Salinities	20,000 - 120,000 ppm TDS
Oil Viscosities	0.18 - 1.0 cP
Rock Permeabilities	100-2000 mD

TABLE 2

MINIMUM OIL PRICES REQUIRED FOR ECONOMIC APPLICATION

	per barrel
Polymer	$15
Surfactant	$20 - 25
Gas	$15 - 20
Heavy Oil	$20 - 30

TABLE 3

NITROGEN COSTS FOR BREAKEVEN ON TERTIARY GRAVITY STABLE GAS INJECTION PROJECT

Reservoir Pressure (psi)	3500	3500	5500	5500
Oil Price ($/bbl)	15	20	15	20
% S_{or}	25	25	25	25
% Recovery of S_{or}	50	50	50	50
N_2 Cost to Breakeven ($/tonne)	40	25	30	35

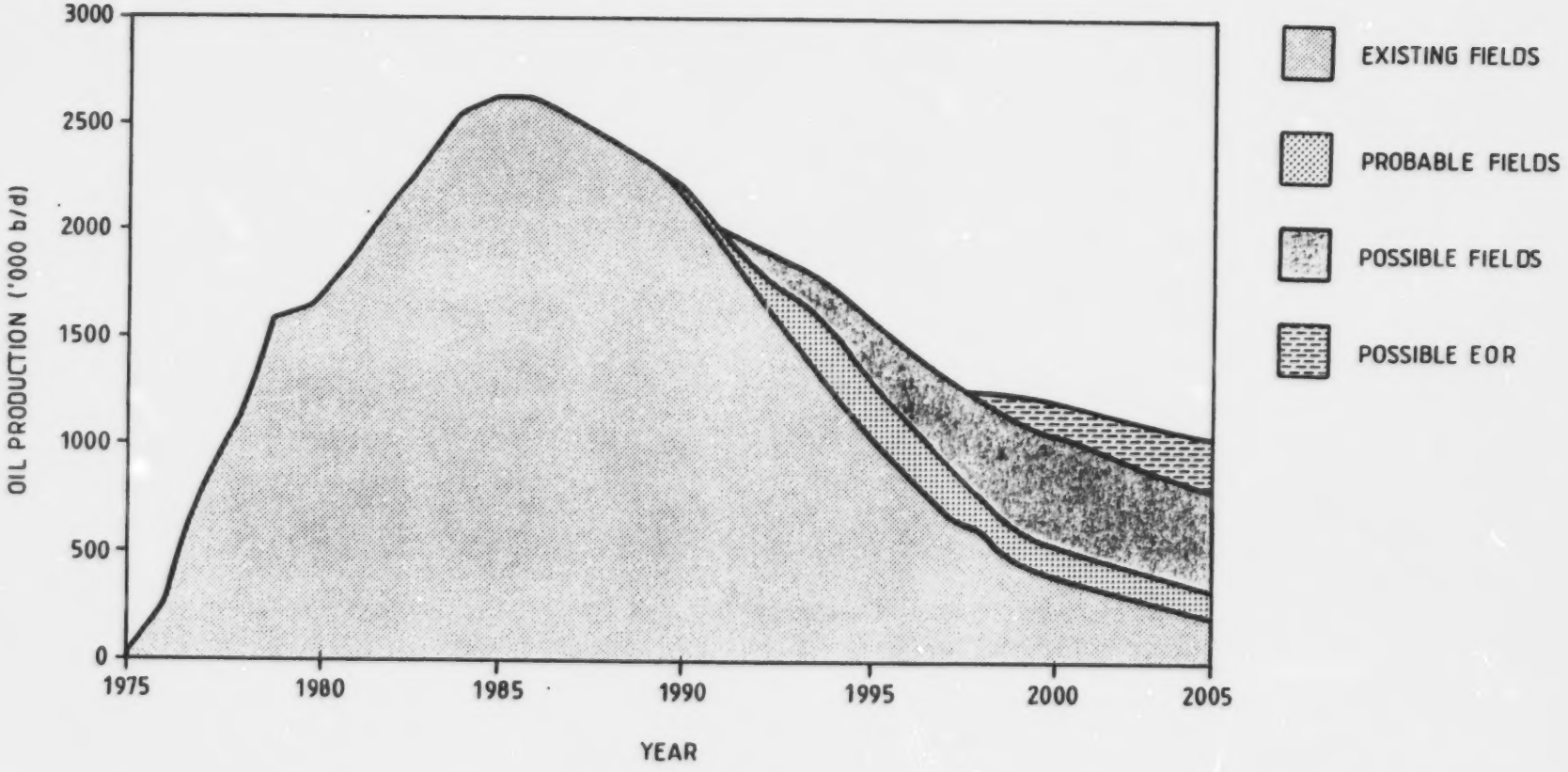


FIG.1 OIL PRODUCTION FORECASTS FOR UKCS

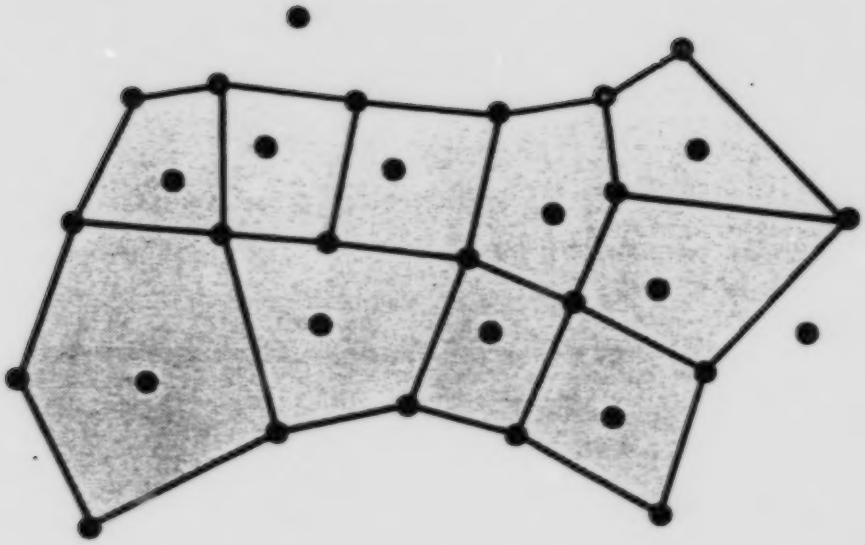


FIG.2 INVERTED 5-SPOT SURFACTANT FLOOD

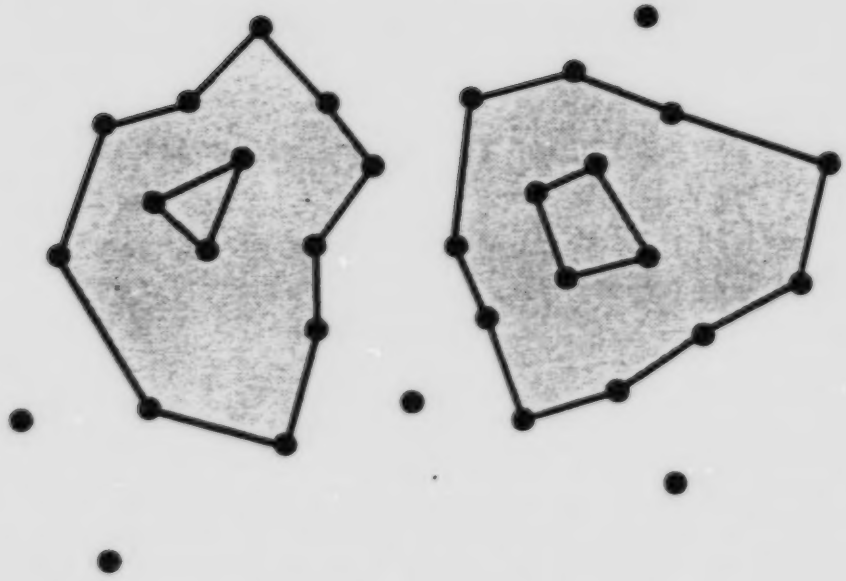


FIG.3 PATTERN SURFACTANT FLOOD

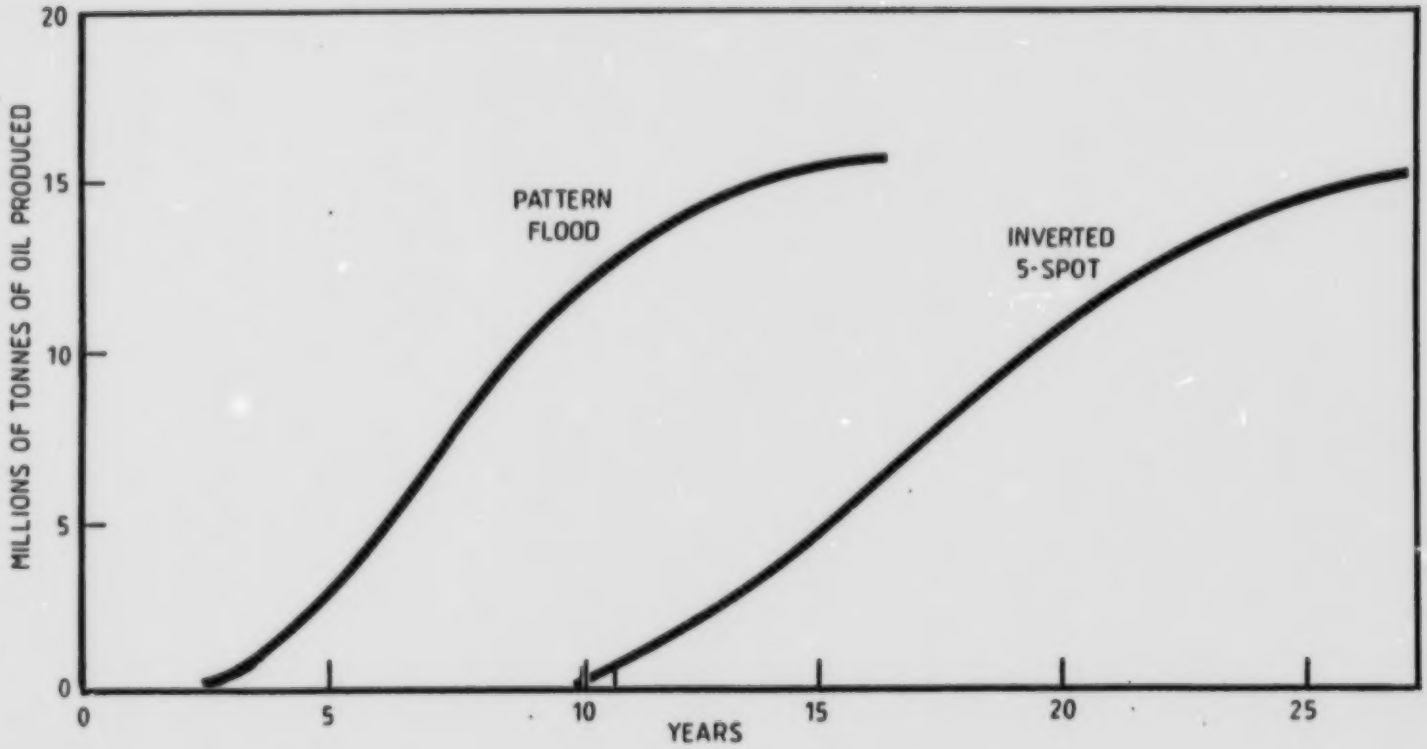


FIG.4 OIL PRODUCTION FOR FLOODING STRATEGIES

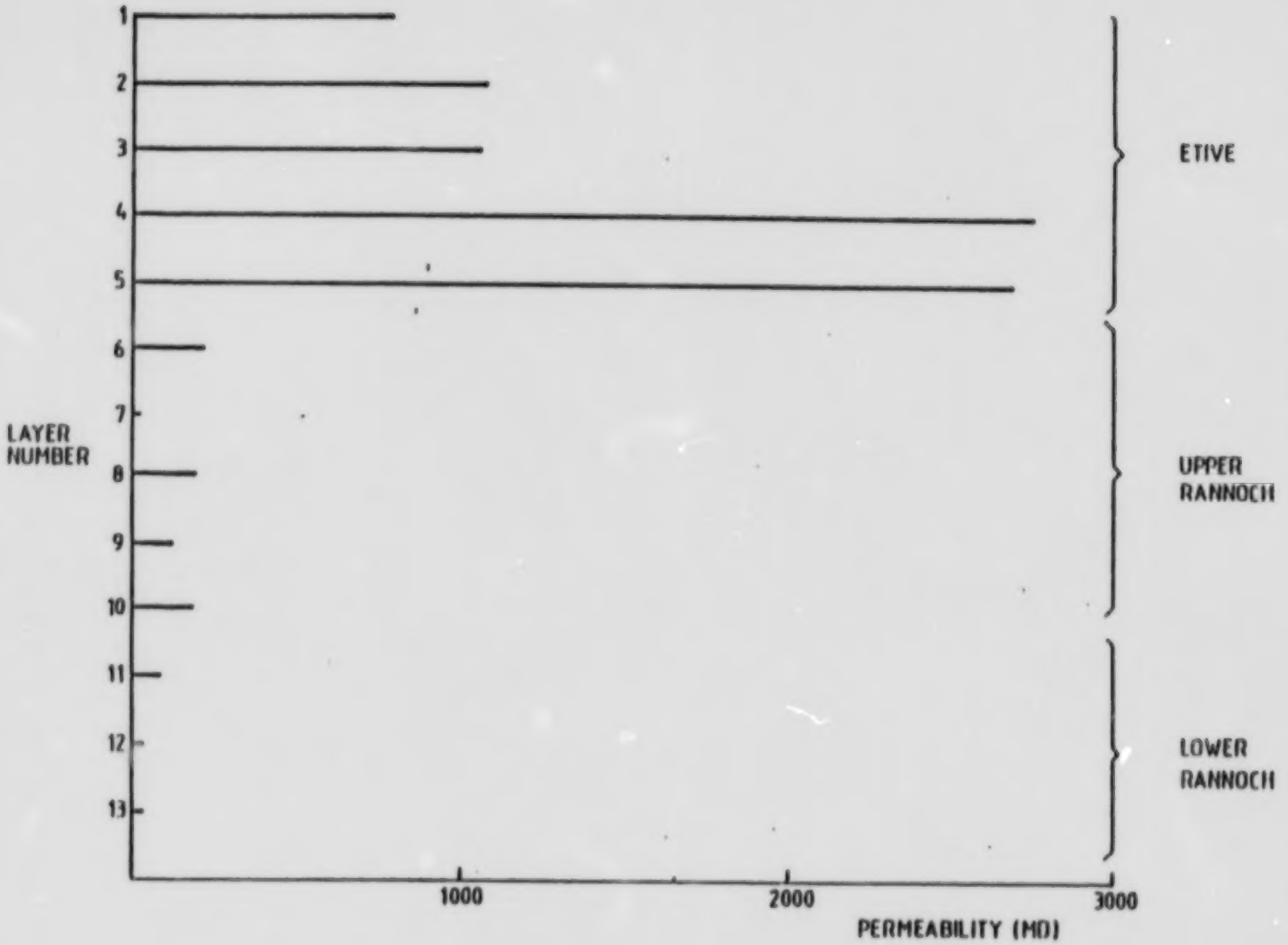


FIG.5 CONTRAST IN THE ABSOLUTE HORIZONTAL PERMEABILITIES BETWEEN THE LAYERS IN THE BRENT SAND CROSS-SECTION

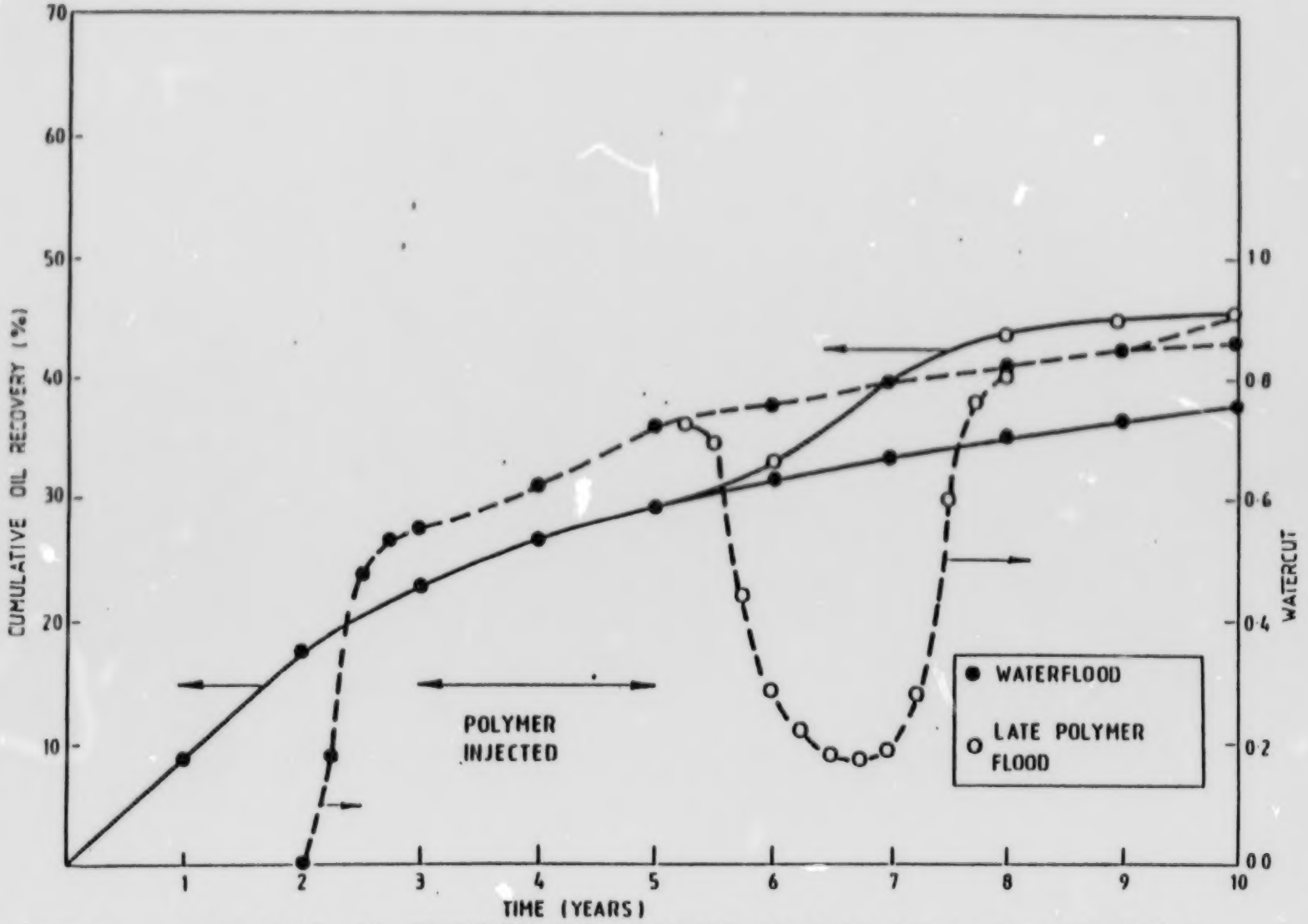


FIG. 6 CUMULATIVE OIL RECOVERY AND WATERCUT PROFILES FOR LATER INJECTION OF BIOPOLYMER COMPARED WITH WATERFLOODING.

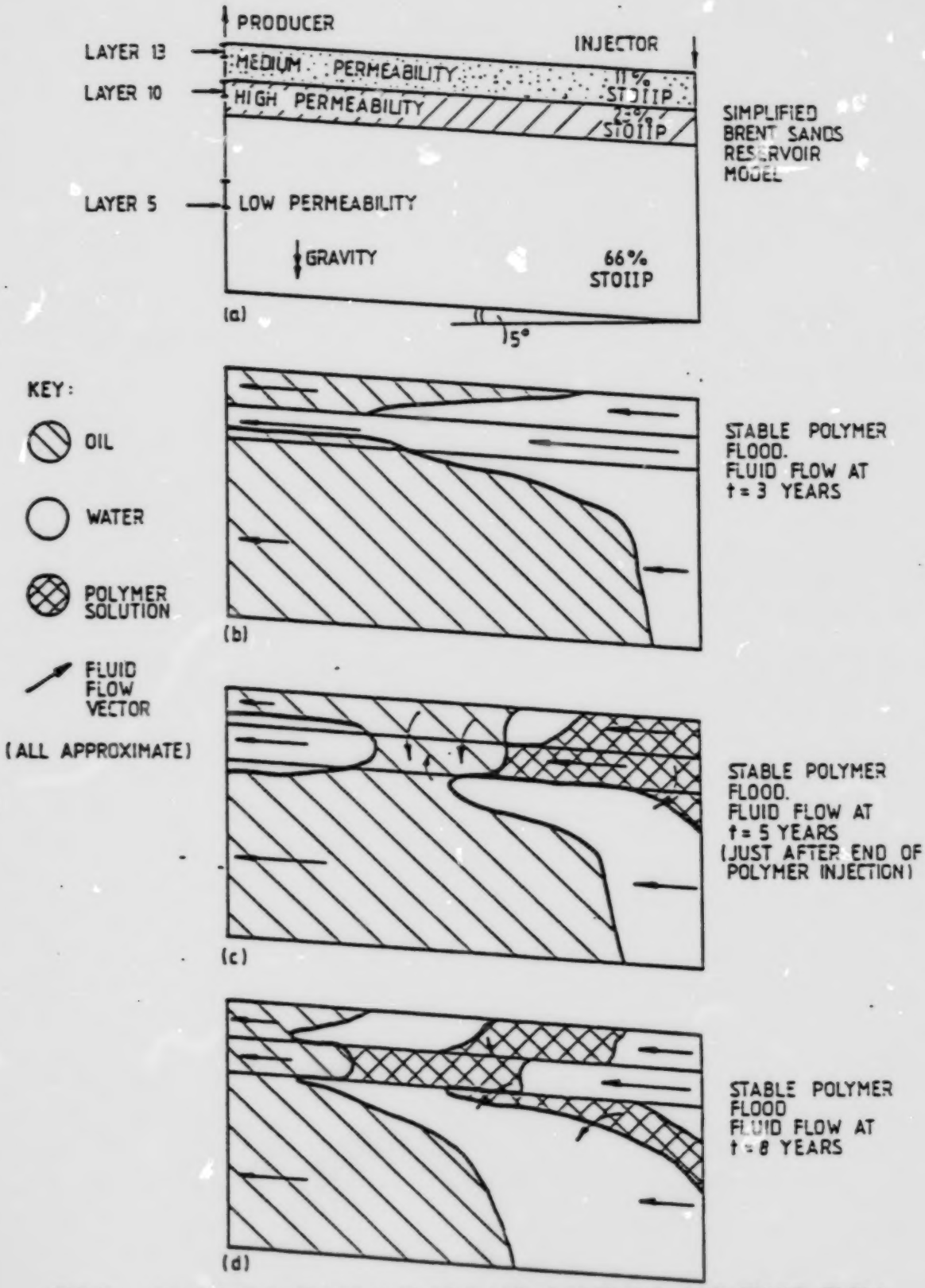


FIG. 7 SCHEMATIC DIAGRAMS OF FLUID POSITIONS AND FLUID FLOW DURING A STABLE POLYMER FLOOD OF THE BRENT SANDS RESERVOIR.

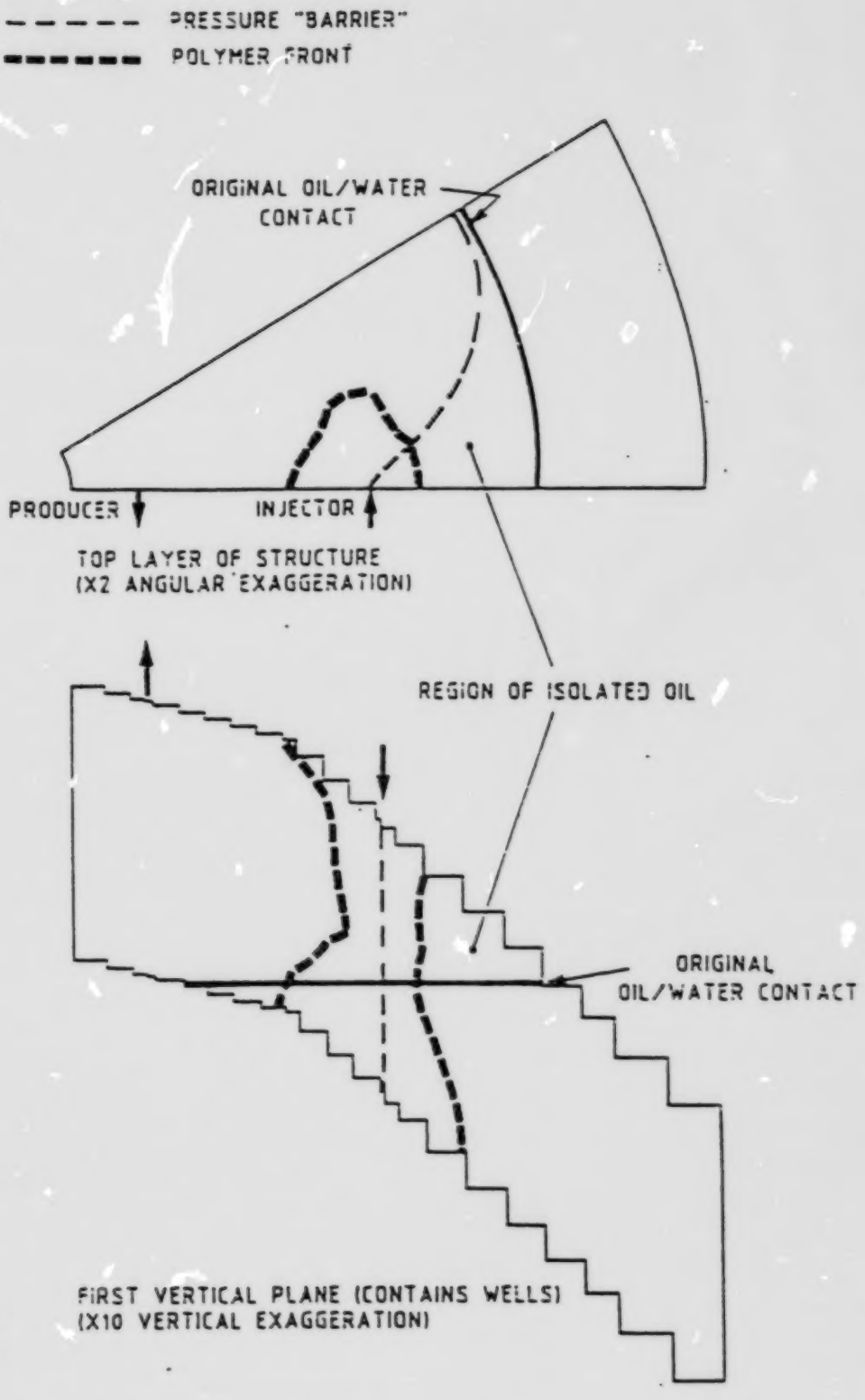
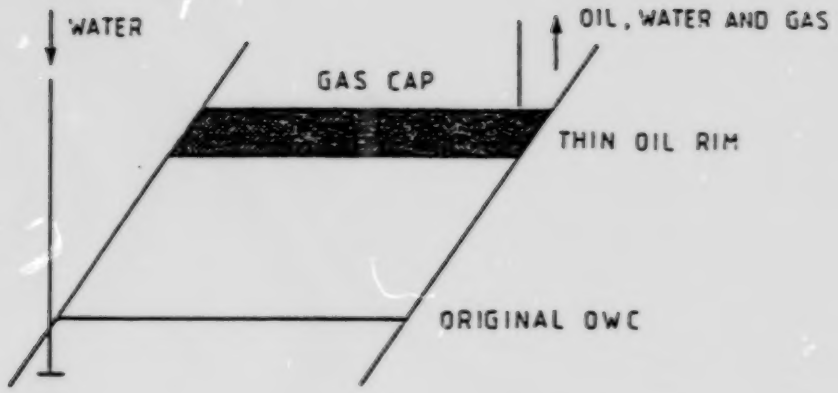
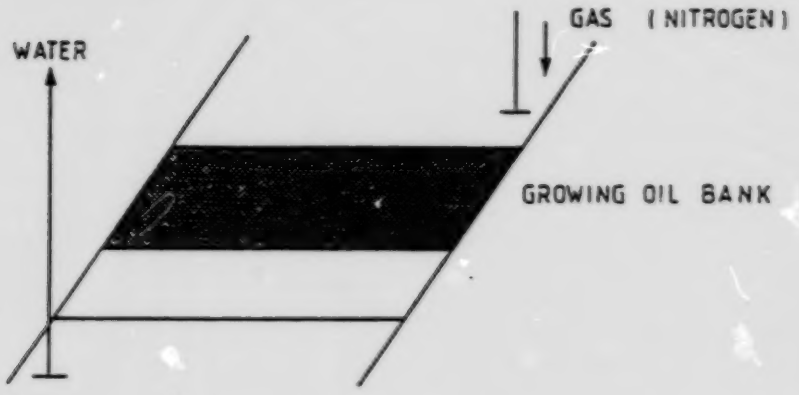


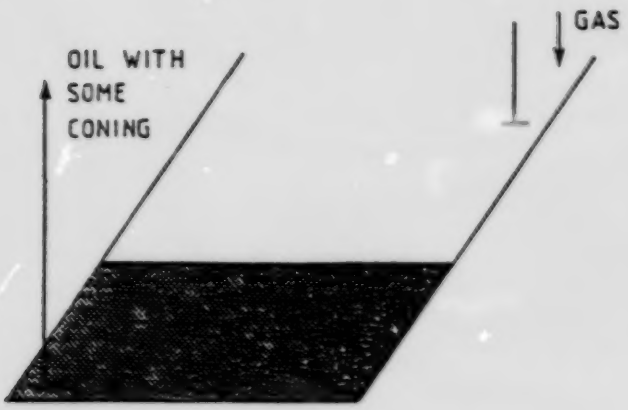
FIG.8 POSITION OF POLYMER FRONT AND PRESSURE BARRIER AFTER 3 YEARS OF POLYMER INJECTION SHOWING REGION OF ISOLATED OIL.



(a) END OF WATERFLOOD



(b) OIL BANK DISPLACED DOWNWARDS



(c) OIL BANK PRODUCTION

FIG.9 SCHEMATIC DIAGRAM OF OIL RECOVERY WITH TERTIARY NITROGEN INJECTION.

PROSPECTS FOR OIL EXPLORATION ACTIVITY WORLDWIDE

Presented by
Clarence P. Cazalot, Jr.
General Manager, Frontier Exploration
Texaco Overseas Holdings Inc.
Bellaire, Texas
U.S.A.

At
The Seventh Annual CERI
International Oil and Gas Markets Conference
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Convention Centre
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GOOD EVENING.

I am pleased to be in the dynamic City of Calgary, and I am honored to be able to address this distinguished group, particularly on a subject that I believe is both timely and of utmost importance to all of us.

I must say that when I was first asked to speak on the outlook for worldwide exploration activity, I felt somewhat intimidated and perhaps even inadequate. This was because prior attempts to predict worldwide exploration activity, by individuals far more qualified than myself, have more often than not proven to be far off the mark. Nevertheless, I accepted the challenge and I will attempt tonight to outline my views and the underlying reasons for them.

In assessing exploration activity, it is essential to understand the factors that drive or control this activity. While these factors are numerous, I have identified three key factors that I believe will determine the level of future exploration activity. I will address each of these factors and the extent to which they will influence exploration.

The most often cited factor affecting exploration activity is the market price for oil and gas. There is little question that exploration activity closely follows the ups and downs of oil prices. Oil prices influence

exploration from the standpoint of both capital available for exploration and the economic viability of exploration prospects or plays. With the close correlation that we have historically seen, it's logical to assume that if one knew what oil prices would do in in the future, one could accurately predict levels of exploration activity. While this may generally prove to be correct, I believe that there have been some fundamental changes in the way the international oil industry views oil prices.

First of all, at the current range of prices of $15-18/bbl, there is considerably less downside risk in prices than there was at $30-35/barrel. Secondly, the industry has now reprogrammed itself to operate within the current range of prices and programs that are pursued (whether exploratory or other) will have to show reasonable economic returns at the lower price levels. The net result of this will be a more consistent albeit-lower level of exploration with much less fluctuation than has historically been the case.

With regard to capital availability, there has also been a shift in industry's thinking as to the financing of exploratory programs. In more prosperous times, capital-constrained companies were willing to borrow money to finance their very aggressive, far-flung exploratory programs. But today, debt reduction is a key objective of many companies thus requiring that exploration (and all other investments) be funded from internal cash flow. This too, has yielded a lower but more stable level of exploration spending by industry.

A second key factor which significantly impacts exploration is the availability of fair and reasonable economic terms coupled with the security and sanctity of contracts. This is one area that has been favorably impacted by the decline in oil prices because model contract terms have improved substantially as to bonuses, royalties, minimum work obligations and economic parameters. I will discuss several examples later of how improved contract terms have greatly increased exploration activity and more importantly, led to the discovery of new reserves. Continued improvements will be needed if industry is to sustain a reasonable level of worldwide exploration, particularly as the industry gears itself to overall lower oil prices and exploration moves to higher risk, frontier areas.

The third factor, which I'm probably better qualified to address, involves the prospective areas or opportunities that will be the focus of exploration.

To give you some idea of where future exploration efforts may be directed, I'd like to take you on a brief tour of the world. Most of the slides I'll be showing you have been borrowed from my good friend, Michel Halbouty, who is one of the most renowned and respected international explorationists in the world.

[SLIDE 1] - EXPLORATORY STATUS OF WORLD'S BASINS

The first slide shows the overall exploratory status of the world's sedimentary basins. There are about 600 recognized sedimentary basins in the world and only about 400 of these basins have been explored. This leaves roughly 200 unexplored basins, shown in green on this slide, remaining to be tested. If exploration yields the same results on these 200 basins as were achieved on the 400 basins already explored, one could project that 80 of these unexplored basins would ultimately be commercially productive. Admittedly, many of these basins are located in remote or hostile parts of the world which is, to a certain extent, the reason that they have remained unexplored. However, in recent years we have seen a willingness by industry, primarily the major companies, to begin exploring these frontiers in the hope of finding new giant fields with reserves far greater than those that can be found in the established producing areas.

I don't want to give the impression that most exploration will focus in these unexplored or frontier areas. In fact, the majority of exploration will continue to be in the established producing areas of the world.

We'll now look at the world in greater detail:

[SLIDE 2] - CIRCUM-ARCTIC AREA

I've chosen the Circum-Arctic area to begin because it has been and will continue to be an area of intense interest and exploration. The

provinces shown in red on this slide are those that are currently productive or for which production plans are being formulated while areas shown in yellow are sedimentary provinces which are prospective but are not yet productive.

Starting with Alaska, there is considerable interest in three areas: the Beaufort Sea (even after Mukluk); the Arctic National Wildlife Refuge (ANWR), which is still embroiled in a political struggle; and a new frontier area in the Chukchi Sea Basin, where industry recently bid quite aggressively in a Federal lease sale for large multi-billion barrel type structures. The Chukchi Sea is a totally undrilled area with very high development costs and yet the total high bids for leases in this frontier area exceeded the high bid total in the most recent Federal Sale in the Western Gulf of Mexico.

In the MacKenzie Delta/Beaufort area of Canada, a great deal hinges on the success of the lead development project, Amuligak. Although delineation drilling results on the eastern and southern flanks of the structure have been disappointing, the development should still proceed and will be the key to tying in smaller existing discoveries and reopening exploration in this important area.

The existing discoveries in the Canadian Arctic islands are clearly dependent on higher oil and gas prices before development can be justified.

Greenland has numerous frontier basins, most of which will require new technological developments and higher oil prices to warrant exploring. But the potential is clearly there, particularly on the eastern offshore area, for discoveries similar to those made offshore Norway.

The Barents Sea continues to have promise but industry's enthusiasm has been dampened considerably by the disappointing results obtained in both the Norwegian and Soviet sectors.

[SLIDE 3] - EUROPE

The focus of activity in Europe will continue to be in the U.K. North Sea. Surprisingly, large new discoveries have been made recently in Eocene

(Tertiary) age rocks in the North Sea. These discoveries were made in stratigraphic rather than structural type traps and were only detectable through the use of sophisticated new geophysical technology. These finds, which may lead to other new plays, combined with favorable economic and tax incentives in the U.K. and new production technology which permits development of fields with as little as 5 million barrels of oil, will all contribute to a high level of industry activity. As evidence of the area's potential, a recent estimate by British Petroleum indicates that a most likely volume of 8 billion barrels of new oil reserves remain to be found in the U.K. North Sea.

Activity will remain high offshore Norway but the emphasis, at least near-term, will shift to delineation of existing discoveries rather than new field exploration. This is due to the Government's implied policy of "queuing" of oil and gas field developments, which eliminates incentives to explore in the near-term. Exploration success rates offshore Norway have historically been quite high with a 58% success rate being achieved in 1987.

Another play in Europe that has been very active in recent years is the Paris Basin. Although this is a very active and successful play for the companies such as Triton and Exxon that are already involved, there is little opportunity for newcomers to acquire good prospective acreage in the basin.

[SLIDE 4] - AFRICA - SOUTH AMERICA

This slide shows only the offshore productive and potential areas of Africa; it does not show the onshore areas, but I will, of course, address the onshore areas in my remarks.

The most attractive current exploratory opportunities in Africa are in two areas: the Western Desert of Egypt and the producing basins on the West Africa Coast in Angola, Gabon, and Nigeria.

The Western Desert of Egypt has had an overall success rate of 32% and in 1987, seven new oil and gas discoveries were made. Exploration activity will continue to be quite high in this area as a large number of newly acquired

blocks are explored by industry. As a side note, the Gulf of Suez also remains quite active but the size of new discoveries in this area appears to have dropped considerably (30-50 MMBO range).

Moving to the west coast of Africa, Angola has continued to increase its production (1987 avg. 357 MBOPD) beyond expectations because of very successful exploration results. This exploration effort was in large part driven by the low operating costs and high quality crude available in Angola. The recent award of three new offshore blocks, coupled with ongoing activity on existing concessions, will ensure a continued high level of exploration in Angola.

In Nigeria, the Government is seeking to increase its reserves from the current 16 BBO to 20 BBO and in order to achieve this, it is considering offering new incentives for exploration and a plan to utilize natural gas for regional consumption. These incentives, combined with new license rounds, should generate increased exploration in Nigeria.

The most active country in coastal west Africa at the moment is Gabon, where very significant discoveries have been made in recent years both on and offshore. The Rabi Kounga discovery made by Shell/Elf alone may boost Gabon's reserves by 50%. This discovery has generated so much interest that in a recent licensing round, virtually all of the on-trend acreage was leased with substantial competition.

Elsewhere in Africa, exploration will focus for the most part in nonproducing or frontier areas such as the East Africa Rift (where Amoco has been quite active). Another bright spot may be Madagascar where PCIAC made a significant gas discovery earlier this year.

SOUTH AMERICA

Turning to South America, no other country can match Colombia in terms of the amount of foreign E&P investment. The Colombian boom was, of course, caused by Oxy's discovery of the Caño Limon field in the Llanos Basin in 1983.

The prognosis is good for continued activity both in the Llanos and Upper Magdalena Basins but the most serious threat to Colombian exploration lies in the continual guerrilla attacks on the Caño Limon-Coveñas pipeline.

Ecuador is an excellent example of a country whose efforts to adopt exploration incentives to attract foreign investment have been very successful. The result is that Ecuador is in the midst of an exploration boom that could attain record levels in 1988 because at least 12 operators plan seismic and/or drilling operations this year.

Like Ecuador, Argentina has aggressively sought to attract foreign exploration capital through new petroleum laws, a more favorable model contract, and a series of licensing rounds. The response has been quite favorable and last summer, 27 companies submitted bids on contract areas in five basins. These new awards will generate substantial exploration activity.

In Brazil, Petrobras' success in the deep water Campos Basin has been outstanding and has placed Petrobras at the forefront of deep water technology. This deep water success has now been extended beyond the Campos Basin by a 1987 oil discovery (3000 BOPD) in the Sergipe-Alagoas Basin, 800 miles to the northeast. Turning onshore to a higher risk frontier area, Texaco is currently drilling the second of a four-well program on Marajo Island, near the mouth of the Amazon River. Texaco earlier disclosed that unevaluated shows of hydrocarbons were indicated near total depth of the first well.

The only factors which may limit exploration in Brazil are limited capital avails for Petrobras and what appears to be an almost certain ban of additional risk contracts for both foreign-owned and domestic-owned companies.

Elsewhere in South America, Peru, Chile, Guyana, and Bolivia are aggressively promoting foreign investment in exploration with some success.

[SLIDE 6] - NORTH AMERICA

Moving north to the U.S. and Canada, we're confronted with fairly mature exploration provinces but both of which still contain high potential

frontier areas. Once again, this slide does not show the onshore productive and potential areas.

In the U.S., the Gulf of Mexico has been and will continue to be the most active and successful exploration province. Operators are moving into even deeper waters as good opportunities on the shallow water shelf have become harder to find. Significant frontier potential still exists on the continental shelves of both the East and West Coasts.

The U.S. onshore basins are, for the most part, in a very advanced stage of exploration and the remaining prospects are quite small, particularly when compared with opportunities available internationally. As a result, most major companies and now several independents have begun directing less of their exploration dollars to U.S. onshore exploration and more to international exploration. Although at a lower rate, U.S. onshore exploration on a selective basis will still be a viable approach for many companies due to the existing infrastructure which permits reasonable profitability of these smaller finds and the overall lower risk, both geologically and politically.

Activity in Canada continues to be focussed in the Western Canadian sedimentary basin. Spurred by Government's incentives, drilling activity rose 18% in 1987 over 1986 levels and industry spent nearly 40% more at Alberta Government sales in the first 5 months of 1988 as compared to the same 1987 period. Although Western Canada is also a mature exploration province, exploration success rates remain high (55.6% in 1987) and a high percentage of the discoveries (69.5%) were oil discoveries. With these positive results, the outlook is for sustained high levels of activity in Western Canada.

The Canadian East Coast has received a badly needed boost in the approval and support of the Hibernia development plan. This lead project will allow further exploration and development of these highly prospective offshore basins.

[SLIDE 7] - NEAR EAST - FAR EAST

As we jump half-way around the world to the Near East, one of the hottest exploration areas is in the Yemen Arab Republic of North Yemen. This activity has been sparked by Hunt Oil's 1984 discovery of the Alif Field which now, combined with subsequent discoveries in the area, is estimated to contain about one billion BO. This a true success story in that prior to Hunt's initial wildcat in 1984, this area was a totally undrilled frontier basin. Now in 1988, only five years later, production is expected to reach 175,000 BOPD. The productive trend is now being extended into South Yemen. New exploration efforts are also underway in other Near East countries such as Jordan, offshore Qatar, Oman and Syria. In Syria, Shell/Pecten has made several new discoveries since 1984 that should continue to make Syria nearly self-sufficient in crude.

Pakistan has experienced a very active and successful round of exploration in recent years. At present, 11 companies have applied for new exploration licenses. Most of the current and planned activity is in the Indus Basin in the southern part of the country but renewed exploration is underway in the Potwar Basin to the north.

India set out about two years ago to offer for bidding 27 blocks on its eastern and western offshore areas. Twelve bids were submitted on nine blocks and acreage awards have now been made to Chevron/Texaco (4 blocks totalling 9 MM acres), Amoco, BHP, Shell, IPC, and Albian. Seismic operations are already underway in these areas and exploratory drilling should commence in 1989.

In Malaysia, the Government's decision to liberalize its production sharing contracts in 1985 has resulted in the award of 10 new contracts. All of these contracts carry drilling obligations so a substantial amount of exploratory work will be conducted in Malaysia over at least the next three years.

In Indonesia, drilling has been on the decline since 1985 and the number of new contracts issued declined dramatically over the 1983-1986 period. However, recent relaxation of investment and operational requirements and improved economic incentives (particularly in frontier areas) has resulted in the award of twice as many new contracts thus far in 1988 as were awarded in all of 1987. The mature provinces of Central Sumatra continue to yield good discoveries such as Caltex's recent PAK 1 discovery which tested 4,835 BOPD. The frontier areas of eastern Indonesia are also attracting attention due to Union Texas's 1985 oil discovery at Tiaka in Sulawesi.

Although not expected to have considerable activity in the near-term, Papua New Guinea is only sparsely explored but the country's potential is clearly evidenced by Gulf's large onshore Iagifu oil discovery. The remoteness of this discovery and low oil prices will delay further exploration and development of this trend.

Exploration activity in China continues to increase, with drilling in 1987 increasing for the 8th straight year. Production also reached a new high for the fifth year in a row. In the South China Sea, there have been some recent successes in what has been an overall disappointing exploration play. The ACT Group (comprised of Agip, Chevron, Texaco) recorded the highest flowrate ever (26000 BOPD) from an exploration well in Contract Area 16/08. Amoco apparently also has made a significant discovery in deeper water on Contract Area 29/04. These new discoveries, combined with the Government's willingness to provide incentives for marginal field development, could rekindle industry interests in this area.

[SLIDE 8] - AUSTRALIA

In recent years, exploration activity offshore Australia has been depressed due to high taxes, high operating costs, and low crude prices. But recent fiscal changes, in the form of reduced taxes and relaxed foreign investment rules, are beginning to attract explorers back to Australia. Their interest is also increased by BHP's continued success in the Timor Sea, which should prompt further evaluation of Australia's other sparsely explored offshore areas.

SLIDE OFF

Well that's a very quick world tour but I've attempted to at least mention those areas that I believe will be the focus of exploration in the next few years.

I'd like to conclude by saying that I believe exploration will continue to be a major priority for oil companies but that in the very volatile oil price environment we're facing, companies will be quite selective and will focus their efforts in those areas where they can compete effectively and profitably.

Ladies and Gentlemen, I thank you for your interest and I want to again thank CERI for this opportunity to come to Calgary to address your fine organization.

I'll be glad to answer any questions you may have.

CPCjr:srf
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THE SOUTHERN CALIFORNIA GAS MARKET

Presented by

Robert M. Loch
President
Pacific Interstate Transmission Company
Los Angeles, California

At

The Seventh Annual CERI
International Oil and Gas Markets Conference
September 18 - 20, 1988
Convention Center
Calgary, Alberta

The Southern California Gas Market

FIG 1

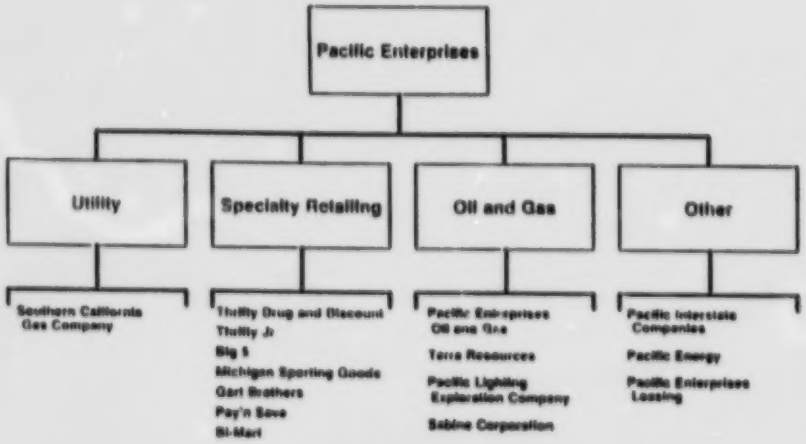


FIG 2

Southern California Gas Company

Largest LDC (annual sales and customers)

4.3 million customers

1.063 Tcf throughput in 1987

771 Bcf total sales in 1987

$2.0 billion purchased gas cost expenses in 1987

FIG 3

THE SOUTHERN CALIFORNIA GAS MARKET

Presented by

Robert M. Loch
President
Pacific Interstate Transmission Company
Los Angeles, California

I. Introduction(Fig. 1)

A. Pacific Enterprises(Fig. 2)

1. Five billion dollars of assets, 5.3 billion dollars in revenues.

2. Three principal lines of business

a. The utility, the Southern California Gas Company (SoCalGas), comprises 50% of total assets.

b. Pacific Enterprises Oil and Gas--an exploration and production company, has operations in the U.S., Canada and the Dutch North Sea.

c. Thrifty Corporation--operator of 800 drug stores and sporting goods stores throughout the west.

d. Other -- smaller lines of business, including the Pacific Interstate companies whose mission is to support SoCalGas as a supplier.

B. Southern California Gas Company(Fig. 3)

1. SoCalGas is the largest gas distribution Company in terms of annual sales and number of customers.

Major Direct Pipeline Systems To Southern California

FIG 4

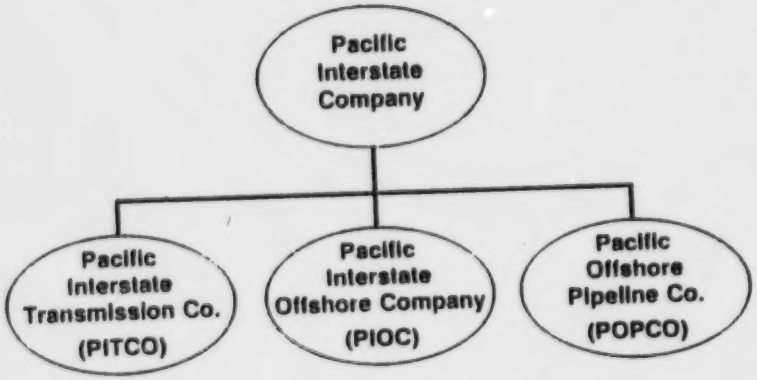

Pacific Interstate Company
Pacific Interstate Transmission Co. (PITCO)
Pacific Interstate Offshore Company (PIOC)
Pacific Offshore Pipeline Co. (POPCO)

FIG 5

2. Serves over 4.3 million customers in a service territory with a population of 14 million people.

3. During 1987 SoCalGas sold 771 Bcf and realized a total system throughput of 1.063 Tcf.

4. SoCalGas' purchased gas costs totaled $2.0 billion dollars during 1987.

II. Sources of Supply(Fig. 4)

A. El Paso system can deliver up to 1750 MMcfd (638 Bcf) into the SoCalGas system primarily from Southwest U.S. gas supply basins.

B. Transwestern system can deliver up to 750 MMcfd (274 Bcf) into the SoCalGas system primarily from Southwest U.S. gas supply system.

C. SoCalGas expects to receive 215 MMcfd or 7% of total throughput from California sources (affiliated and non-affiliated) through regular purchases or exchange.

D. Although SoCalGas' pipeline suppliers have no direct connections with Canadian suppliers, significant quantities of Canadian gas arrive in southern California by displacement.

E. (Fig. 5) Pacific Interstate Company, a SoCalGas affiliate, supplied 132 Bcf to SoCalGas or 17% of the utility's annual sales requirements during 1987.

1. Pacific Interstate owns two FERC regulated interstate pipelines that transport natural gas from production fields off the coast of California -- PIOC and POPCO.

PITCO's Canadian Gas Delivery System

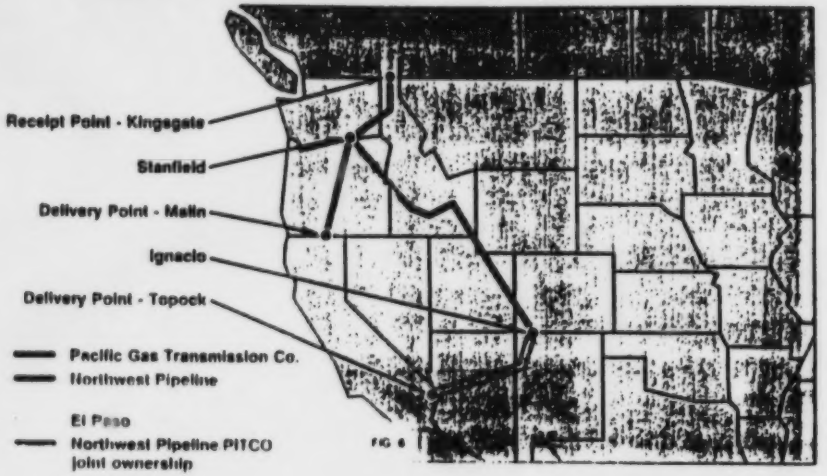


FIG 6

Canadian Gas Received by SOCALGAS in 1987

- 80 Bcf (219 MMcfd) firm from Pan-Alberta
- 4 Bcf (11 MMcfd) best efforts from Pan-Alberta
- 18 Bcf (49 MMcfd) as available from Westcoast Energy

FIG 7

Canadian Gas Sales to Southern California

- 240 MMcfd firm from Pan-Alberta under an export authorization approved to the year 2012
- 60 MMcfd best efforts from Pan-Alberta
- 640 MMcfd best efforts from Pan-Alberta and Westcoast Energy (pending FERC authority to resell to SOCALGAS)
- Other volumes bid into SOCALGAS' short-term purchase program

FIG 8

2. Pacific Interstate owns part interest in certain FERC-regulated pipeline facilities used to transport Canadian gas to southern California -- PITCO.

   a. (Fig. 6) Pacific Interstate takes title to the gas at the international border near Kingsgate, B.C, using the "prebuild" facilities authorized as part of the ANGTS system.

   b. Canadian gas actually enters the SoCalGas system via displacement from the El Paso system or Pacific Gas Transmission (PGT) systems.

3. (Fig. 7) During 1987, 113 Bcf of Canadian gas was purchased by Pacific Interstate at the international border, which allowed 102 Bcf to be delivered into the SoCalGas system.

   a. The 102 Bcf delivered into the SoCalGas system included 80 Bcf received on a firm basis from Pan-Alberta Gas Ltd. of Calgary.

   b. Under the terms of SoCalGas' short-term purchase program, another 18 Bcf was received on a best efforts basis from Westcoast Energy Inc. of British Columbia.

4. (Fig. 8) Pacific Interstate currently purchases 240 MMcfd on a firm basis from Pan-Alberta under an export authorization approved to the year 2012.

5. Pacific Interstate is authorized to purchase on a best efforts basis another 60 MMcfd from Pan-Alberta.

6. Pacific Interstate is also authorized to import an additional 640 MMcfd on a strictly best efforts basis; it is awaiting FERC authority to resell the gas to SoCalGas.

   a. The gas may be received from Pan-Alberta or from Westcoast Energy.

   b. Capacity on pipeline facilities needed to transport the gas is expected to limit the quantity of gas arriving in southern California under this agreement.

   c. Pacific Interstate collects only a fee of 1¢/MMBtu to cover out-of-pocket expenses, eliminating unnecessary middle man market-up expenses and Pacific Interstate's profit on the transaction.

7. Additional volumes of Canadian gas are often bid into SoCalGas' spot gas purchase program.

Recent Regulatory Changes

FERC order 436

FERC order 500

CPUC statewide investigation

FIG 9

III. (Fig. 9) <u>Recent regulatory changes have significantly affected the role played by the local distribution Company in the gas industry.</u>

A. FERC Orders 436 and 500 have emphasized the open market approach and provided end-users and producers with greater access to supplies and markets.

B. The California statewide investigation aimed at implementing a new regulatory framework for procurement and transportation culminated on May 1, 1988.

   1. (Fig. 10) The new regulatory environment has segregated customers into core and non-core.

New CPUC Approved Regulatory Framework

- Core customers - less than 20,800 therms/month (Approximately 66 Mcf/day) rely on SOCALGAS for complete service

FIG 10

New CPUC Approved Regulatory Framework

- Non-Core customers
  - Use alternate fuels
  - Purchase their own gas supplies from non utility suppliers
  - Purchase utility core supplies
  - Purchase utility short-term gas

FIG 11

SOCALGAS Market Requirements Core and Non-Core

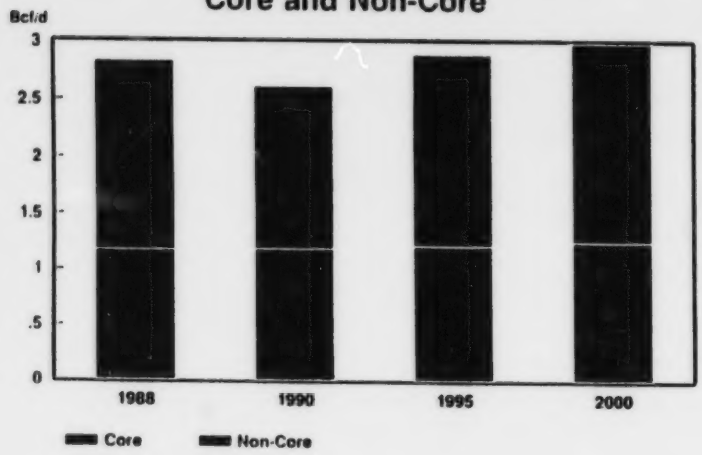


FIG 12

a. Core customers are those customers that use less than 20,800 therms/month. (Customers may not aggregate consumption from several different locations to exceed the minimum consumption level.)

b. (Fig. 11) Non-core customers are generally capable of either using alternate fuels or purchasing their own gas from non-utility suppliers.

c. Under the new regulatory rules, non-core customers may choose to purchase their gas supplies from the utility's core portfolio, the utility's best efforts non-core portfolio, or non-utility suppliers.

d. Currently, SoCalGas' non-core portfolio is limited to one month, best efforts supplies.

e. Proposals for longer-term utility non-core procurement, and utility storage banking service are awaiting the outcome of a separate CPUC investigation.

IV. Core Market Requirements (Fig. 12)

A. In 1988, under average temperature conditions gas sales to the core market are expected to be 1048 MMcfd or 42% of SoCalGas' total throughput.

1. Core market requirements are expected to remain stable throughout the period.

2. More than one-half of SoCalGas' deliveries will be to non-core customers during the period.

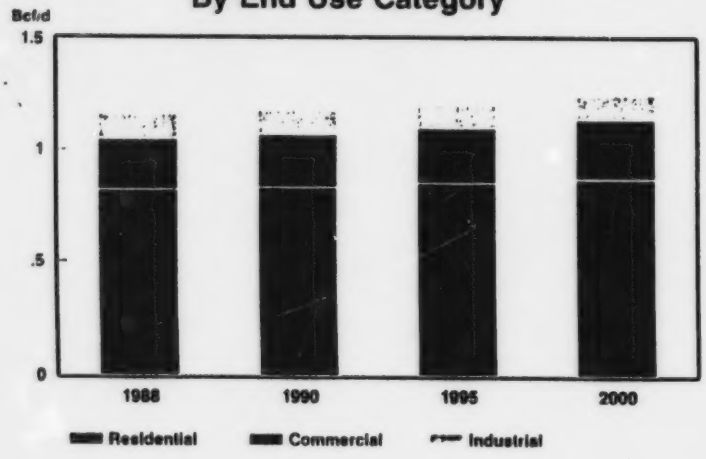


FIG 13

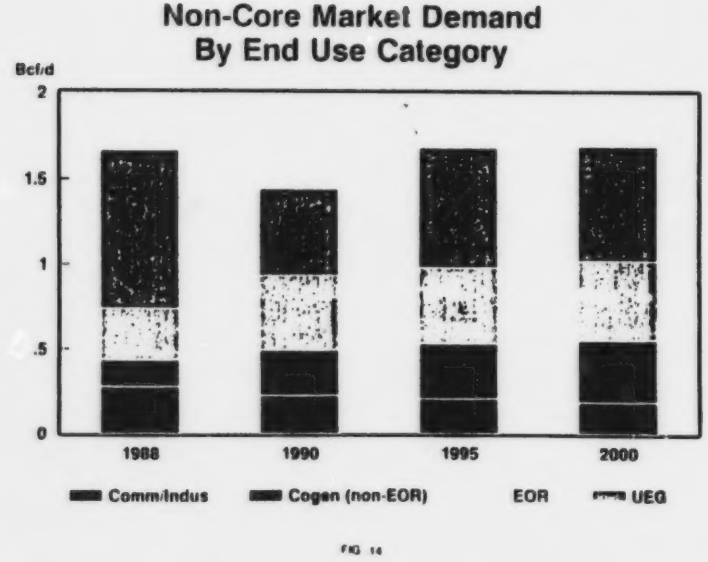


FIG 14

B. (Fig. 13) Residential consumption accounts for 75% of the core market requirements.

1. The decline in residential use per meter has slowed; further declines in residential use per meter will probably be more than offset by growth in the number of meters.

2. Changes in residential rates might stimulate an increase in residential use per meter.

C. Core market requirements will be approximately 120 MMcfd higher or lower depending on whether cold or hot temperature conditions prevail in Southern California.

D. Under average year conditions, core market requirements are expected to increase 8% by the year 2000 to 1137 MMcfd.

V. Non-Core Market Requirements (Fig. 14)

A. The wholesale and retail non-core market is expected to account for 1671 MMcfd or 58% of SoCalGas' total throughput in 1988.

B. Commercial/industrial demand will fall by 100 Bcf over the next twenty years due to the complete phase-out of a large ammonia producer, continued decline of energy intensive industries and increased use of cogeneration in the commercial market.

C. In 1988, gas use by wholesale and retail Utility Electric Generation (UEG) customers is expected to be 916 MMcfd or 55% of the non-core market requirements.

1. SoCalGas delivered 308 Bcf to its retail Utility Electric Generation (UEG) customers during 1987, an increase of 42% over 1986 levels.

2. The increase was due primarily to unusually dry conditions reducing hydroelectric availability in the west and low spot gas prices which allowed gas generation to compete with coal sources from the Southwest.

3. A near-term decline in UEG requirements is anticipated due to the increase in cogeneration projects, return to normal hydro conditions and the initiation of the last Palo Verde nuclear and Intermountain Power Project units.

4. During the 1990's, gas gradually regains its market share until growth in electric demand forces the UEG customers to add new, non-gas generating capacity.

D. Total deliveries for Enhanced Oil Recovery (EOR) steaming and EOR related cogeneration are expected to increase from 215 MMcfd to 460 MMcfd by 1993 before stabilizing in the late 1990's.

VI. (Fig. 15) <u>As a result of the recent regulatory changes, the southern California market now consists of a utility sales market and a direct sales market.</u>

A. Until recently, gas purchased from SoCalGas' traditional interstate suppliers, Transwestern and El Paso, accounted for 80% of the natural gas used in southern California.

B. The regulatory changes discussed earlier have given distribution utilities and end-users the flexibility to purchase their own supplies and reduce the reliance upon traditional suppliers.

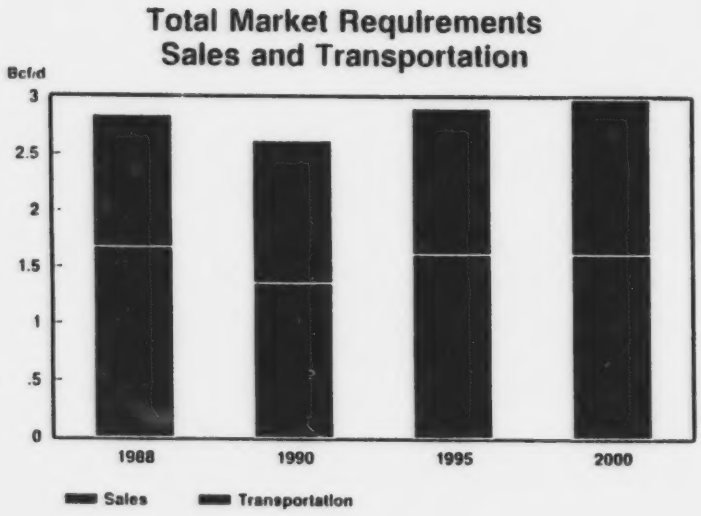


FIG 15

Major Direct & Indirect Pipeline Systems To Southern California

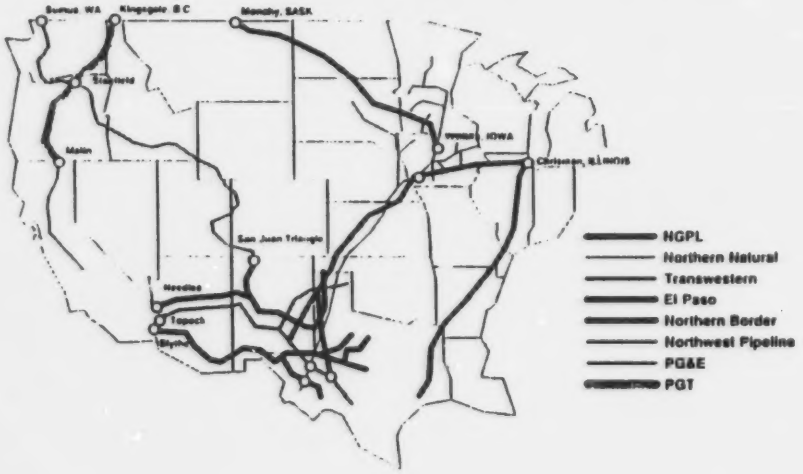
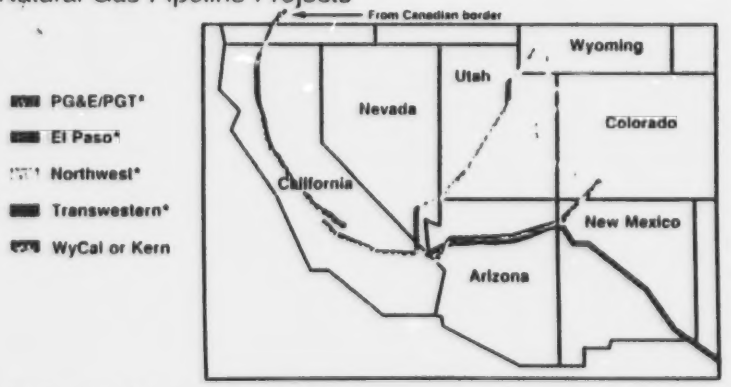


FIG 16

SOCALGAS

Mojave, WyCal and PG&E/PGT
Natural Gas Pipeline Projects



*Existing systems to be looped with varying distances

FIG 17

C. End-user transportation and direct purchases by SoCalGas from non-traditional suppliers have enabled SoCalGas to reduce takes of traditional commodity rate supply to less than 20% of total throughput.

1. In 1987, SoCalGas purchased 874 MMcfd or 31% of its throughput directly from non-traditional suppliers under intermediate and short-term gas purchase agreements.

2. In 1987, end-user transportation accounted for 642 MMcfd or 22% of total throughput and is expected to increase to 40% of total throughput in 1988.

VII. (Fig. 16) <u>The potential for additional Canadian gas sales in southern California is limited at least for the short-term by the availability of pipeline capacity.</u>

A. The gas can be transported across the Northwest Pipeline, Pacific Gas Transmission (PGT) or Northern Border systems if capacity is available, and delivered by displacement through the El Paso system.

1. The delivered cost of Canadian gas must remain competitive with that of other supplies available to SoCalGas.

2. Canadian gas can displace U. S. supplies in SoCalGas' short-term and intermediate purchase programs.

B. (Fig. 17) Longer term, a number of interstate pipeline projects have been proposed to deliver additional gas into the southern California market.

The New Regulatory Environment

- Changes the LDC role
- Re-allocates long-term procurement risk
- Loss of diversity benefits

1. The Kern River Pipeline and the WyCal Pipeline, as proposed, would carry Overthrust and Canadian gas into the EOR market area.

2. Mojave Pipeline Project, as proposed, would carry Southwest U.S. supplies to the EOR market area.

3. Both of these projects, as currently proposed, fail to use the low cost, reliable intra-state transportation provided by SoCalGas and require the needless duplication of transmission facilities within California.

4. Expanded PGT/PG&E facilities would allow additional quantities of Canadian gas to reach southern California on a firm basis.

5. A new pipeline was recently proposed to bring additional volumes of Texas gas through Mexico into southern California.

C. (Fig. 18) SoCalGas is no longer in a position to assume long-term procurement risk on behalf of its non-core market.

1. Major facility expansion projects require twenty year commitments to support the required financing.

2. As discussed earlier, over half of SoCalGas' market is non-core and has no long-term obligation to purchase gas from SoCalGas.

3. Other parties, such as producers and end-users, must be prepared to provide the throughput and revenue guarantees once provided by the distribution utilities in order to support the construction of new supply projects.

D. Until recently, end-users purchasing gas from the utility continued to receive service even if some producers reduced the quantity of gas being sold either directly or indirectly to SoCalGas.

1. The sales revenues received by producers selling their supplies directly or indirectly to SoCalGas were not necessarily tied to the gas requirements of a single customer.

2. Under the new regulatory environment, SoCalGas may no longer be able to provide the diversity benefits previously enjoyed by end-users and producers.

Conclusion

Canadian gas has a future in Southern California

- Large market
- Many transportation routes
- Must be competitive

FIG 19

VIII. Conclusion(Fig. 19)

Although capacity constraints may limit deliveries of additional Canadian gas to southern California from time-to-time, we encourage Canadian gas suppliers to continue to compete for the large southern California market.

DEVELOPMENTS IN THE NORTHEAST AMERICAN GAS MARKET

Presented by
Robert Catell
Executive Vice President
and Chief Operating Officer
Brooklyn Union Gas Company
Brooklyn, New York

At
The Seventh Annual CERI
International Oil and Gas Markets Conference
September 18-20, 1988
Convention Centre
Calgary, Alberta

DEVELOPMENTS IN THE NORTHEAST AMERICAN GAS MARKET

The following summary attempts to highlight the important market, regulatory and sourcing developments for natural gas in the Northeast. There are several characteristics of the Northeast market, as well as current trends in regulatory proceedings which should serve to increase the amount of gas both U.S. and Canadian producers dedicate to the Northeast.

1. MARKET DEVELOPMENTS

* The core market of residential and commercial customers is unsaturated, a fact made especially apparent by comparison to Central and Pacific markets.

* The need for gas-fired generating capacity should continue to grow steadily. From Massachusetts to North Carolina, electric load has grown in the 2-3% range since the early 1980's, with peak demand growing at 4-5% in recent years.

* Many utilities seem to be addressing the continued health of the economy as a base-case.

* Crucial issues such as the Persian Gulf cease fire and how OPEC deals with today's oil producing surplus will dictate the direction of oil prices. It seems that prices could remain relatively stable, in the $14-18 per barrel range for the next few years.

2. REGULATORY DEVELOPMENTS

* If adopted, the draft rules proposed for electricity reform would represent a fundamental restructuring of the upstream sector of the industry. Market entry would be improved for IPPs, and utilities would be almost compelled to obtain new base-load generating capacity through a bidding process open to third-party developers.

* The burden of nuclear plant cancellations and cost overruns, the growing trend of utilities opting out of developing their own supply projects and the robust growth of PURPA capacity during the 1980s should lead to great opportunity for third-party developers, and thus the producers supplying these projects.

* Skepticism regarding the feasibility of gas-fired projects does exist, however. Many electric utility managers doubt the reliability of gas as a primary fuel, largely because of delivery curtailments, the Fuel Use Act of the 1970's and apprehension about long-term availability.

* There is also concern in the Northeast about delays arising from FERC's Open Season proceedings, as well as the reliability of transportation service to the area.

3. SOURCING TRENDS

* Conventional wisdom would dictate that the gas bubble cannot extend indefinitely. However, factors such as the ability of the industrial sector to switch fuels, the projected availability of oil, and additional supply sources could mitigate against a sharp increase in prices.

* Western Canadian gas has clearly found a significant role in the U.S. Northeast. Distributor supply projects such as ANE and end-use generating projects such as Ocean State demonstrate the viability of bringing this gas longhaul to market.

* Many sources could be listed as having potential for the future, the Scotian Shelf and the Arctic, flowing LNG from North Africa, and additional LNG brought on stream within the Atlantic Basin.

GAS MARKETING CHALLENGES IN THE U.S.: A DEVELOPED URBAN MARKET

Presented by

Richard E. Terry
President
The Peoples Gas Light and Coke Company
Chicago, Illinois
U.S.A.

Each of the three LDC's represented on this panel presents a different kind of marketing challenge because each of our companies serves very different markets. These differences can be important because market characteristics will affect the terms on which gas suppliers can successfully compete for our business.

The service area of Peoples Gas is the City of Chicago, where Peoples is the sole gas distribution utility. The Company serves about 850,000 customers. Normal annual sendout is in the area of 250 Bcf.

The Chicago market has four important characteristics. First, it is both mature and stable, with a heavy concentration of residential and commercial use, a relatively small industrial sector and no electric utility consumption. Second, the market probably has a limited potential for overall growth in the future, because of physical and demographic constraints. Third, our market has received and will continue to demand comparatively low cost gas service. Fourth, a fairly large part of our throughput has shifted from retail gas sales to transportation of gas purchased by our customers from other suppliers. The availability of transportation has not resulted in growth of the overall market.

Overall, Chicago's demand for gas has stabilized in recent years, as new residential and commercial load has been sufficient to offset load losses attributable primarily to the industrial sector.

Because of the characteristics of our market, suppliers will have to meet at least three criteria: (1) high reliability; (2) flexibility in required takes; and (3) low price. Our market is heavily weighted toward firm

service, and especially to firm space heating service. Only 4 percent of annual sendout goes to interruptible customers.

Our need for flexibility from suppliers rests largely on the variable demands produced by a temperature-sensitive market. A number of Company-owned facilities plus contracted storage services enable us to manage supply to meet peak and seasonal requirements. Nevertheless, the daily and seasonal swings in our market demand are such that Peoples Gas will continue to require a reasonable degree of flexibility in its takes from suppliers.

Peoples Gas may be in a better position than some other LDC's to achieve its goal of low gas cost from suppliers. One important factor is a favorable geographic location, affording access to many competitive supply alternatives through existing or potential ties to several interstate pipeline systems, including the proposed extension of Northern Border Pipeline Company.

One requirement for supply to compete for our purchases is that the seller must bear the risk associated with the wellhead price of gas. It is fair that producers bear the risk of the cost of gas because producers are the only segment of the gas industry that earns any profit on gas. In contrast to producers, LDC's do not earn any profit on the gas cost portion of their rates. It is unfair to expect LDC's to bear the market risk for the wellhead cost of gas when, unlike producers, they have no countervailing opportunity for reward.

Moreover, it must be recognized that LDC's are financially incapable of bearing any significant market risk for the cost of gas. The reason boils down to one simple financial fact — namely, LDC earnings are dwarfed by annual gas costs. Thus, LDC's lack the financial strength to accept a market risk for any significant proportion of their gas costs. Some say that risk is a feature of doing business in the new deregulated environment. But the current talk about deregulation and a market-driven industry is at best exaggerated. Only producers are being deregulated. Pipeline services remain driven by regulation, not the market.

LDC's, too, remain regulated in essentially the same way as always. Perhaps the greatest impact of regulation on LDC gas purchasing continues to be the effect of regulation outside our local jurisdiction, primarily, the failure of the FERC to provide a clear signal of the comparative price, terms and reliability of the pipeline merchant and transportation options.

The fundamentals of our industry are sound and the future is bright. However, the changing regulatory environment does create uncertainty for both buyers and sellers at the present time.

Alberta Natural Gas Marketing Challenge

Paper given at the:

Seventh CERI
International Oil and Gas
Markets Conference

September 18-20, 1988
Calgary, Alberta, Canada

by: W.L. (Larry) Graburn
Executive Vice President
Resources
Canadian Western Natural Gas Co. Ltd.
Northwestern Utilities Limited
CU Gas

ALBERTA NATURAL GAS MARKETING CHALLENGE

* Is natural gas deregulation evolving the way the signatories of the Western Accord and the Agreement on Markets and Prices had hoped back on 1985? Is the one year transition between regulation and deregulation ever going to be completed? Is there going to be an all out confrontation between Alberta and Ontario over the security of supply issue? How will a Free Trade Agreement with the United States impact on our natural gas industry? How can we as Canadian Western Natural Gas Company, headquartered in Calgary, or Northwestern Utilities Limited, out of Edmonton, plan to meet the challenge of deregulation and ensure that our service and product are competitive, when the groundrules for playing the game are yet to be determined? In fact, will the rules be the same for all who wish to play the game?

These are not new questions, but they are surely some of the questions one has to address when determining what role he wishes to play in the extremely complex and dynamic business of marketing natural gas.

THINGS ARE NOT TOTALLY NEW FOR CANADIAN WESTERN OR NORTHWESTERN, MORE RECENTLY NAMED CU GAS, AS WE AS LOCAL DISTRIBUTING COMPANIES OR LDCS HAVE BEEN IN ALBERTA SINCE 1912 AND 1923 RESPECTIVELY, AND HAVE BEEN EXPOSED TO A FORM OF DEREGULATION IN THE LATE 1970S WHEN GAS SUPPLIES BEGAN TO EXCEED GAS DEMANDS. WITH THE SURPLUS OF GAS SUPPLIES WITHIN ALBERTA, PRODUCERS AND BROKERS BEGAN COMPETING FOR MARKETS THUS AFFORDING SOME CONSUMERS, NAMELY LARGE INDUSTRIALS, OR MORE COMMONLY CALLED NON-CORE CUSTOMERS, THE OPPORTUNITY TO BUY DIRECTLY AND CIRCUMVENT OUR GAS SUPPLIES.

CU GAS WAS NOT IN A POSITION TO COMPETE FOR THESE SALES MARKETS, AS I WILL DISCUSS LATER, AND WE BECAME A TRANSPORTER OF OTHERS' GAS SUPPLIES. SUFFICE TO SAY THAT THE DEREGULATION AGREEMENT ON MARKETS AND PRICES OF 1985 AND OPEN ACCESS AND CHOICE OF SUPPLY IN THE NON-CORE MARKET ARE NOT NEW FOR US, BUT THE QUESTION OF OPEN ACCESS AND CHOICE OF SUPPLY IN THE CORE MARKET IS NEW AND CHALLENGING, PARTICULARLY WHEN MANY BASIC AND FUNDAMENTAL QUESTIONS ARE YET TO BE ANSWERED.

* DEREGULATION BASICALLY CALLED FOR OPEN ACCESS, CHOICE OF SUPPLY, AND SANCTITY OF CONTRACTS, WITH THE OBVIOUS QUESTION BEING ASKED:- ARE THESE

COMPATIBLE OR WILL WE NEED, AS MANY HAVE CALLED FOR, SOME FORM OF "RE-REGULATION"?

WITH THE MAJORITY OF ALBERTA'S GAS PRODUCTION BEING SOLD TO MARKETS OUTSIDE ALBERTA, WE, AS THE MAJOR UTILITIES ARE VERY MUCH IMPACTED BY WHAT THOSE * LOCATED OUTSIDE THE BORDERS OF ALBERTA DO. (I.E. 22% OR 543 PJ MARKETED IN ALBERTA AND 78% OR 1899 PJ MARKETED OUTSIDE ALBERTA, AND THIS EX-ALBERTA PERCENTAGE IS GROWING PRIMARILY IN THE U.S.). OUR WHOLE GAS SUPPLY CONTRACTING STRATEGY AND PORTFOLIO BUILDING, ALONG WITH OUR MARKETING EFFORTS AND OUR PLANS TO STAY COMPETITIVE ARE DIRECTLY AFFECTED BY WHAT HAPPENS IN CALIFORNIA, ONTARIO AND OTHER MARKETING AREAS IN NORTH AMERICA.

WE, LIKE MOST PUBLICLY OWNED UTILITIES, HAVE A NUMBER OF STAKE HOLDERS AND HAVE TO ENSURE THAT ALL ARE SATISFIED IN THIS DEREGULATED WORLD.

WE CAN ONLY ENSURE THAT THEY ARE SATISFIED BY HAVING A COMPETITIVELY PRICED PRODUCT AND SERVICE; <u>BUT</u> AT THE SAME TIME WE HAVE TO MAINTAIN AN ADEQUATE GAS * SUPPLY FOR THE LONGER TERM. THEREIN LIES NORTH AMERICAN'S $64,000 QUESTION ON THE OPTIMAL TRADE-OFF... <u>MARKET RETENTION</u> BASED ON <u>PRICE</u> AND

PRICE BEING DEPENDENT ON SECURITY OF SUPPLY. WHAT ARE THE RULES BY WHICH WE PLAY THIS NEW GAME?

BEFORE I ATTEMPT TO LOOK AT WHAT LIES AROUND THE CORNER FOR US AS MARKETERS IN ALBERTA AND HOW WE ADDRESS THE $64,000 QUESTION, A BRIEF DISCUSSION ON CU GAS AND WHERE WE HAVE COME FROM OVER THE PAST 13 TO 14 YEARS MAY HELP PUT THE ISSUES IN PERSPECTIVE.

* WITH THE HIGH PRICE OF COMPETING FUELS, NATURAL GAS HAS A SECURE HOLD IN ALBERTA WITH 93% OF ALL RESIDENTIAL AND COMMERCIAL CUSTOMERS USING GAS AND 80% OF ALL INDUSTRIALS USING GAS.

CU GAS IS CURRENTLY SELLING GAS TO 85% OF THE RESIDENTIAL AND COMMERCIAL MARKET AND 13% OF THE INDUSTRIAL MARKET.

OUR COMPANIES, SERVE 620,000 CUSTOMERS IN 293 COMMUNITIES THROUGHOUT THE PROVINCE. THE MAJORITY OF OUR CUSTOMERS ARE CONNECTED TO OUR TRANSMISSION NETWORK SPANNING OUR SERVICE AREA AND INTERCONNECTED WITH NOVA. A DIVERSE GROUP OF 275 PRODUCERS PROVIDE US WITH THE MAJORITY OF OUR GAS SUPPLIES.

* OVER THE PAST 13 YEARS, GOING BACK TO 1975, ONE COULD DIVIDE THAT PERIOD INTO THREE DEFINITE ERAS;

ONE FROM 1975 TO 1979, THE SECOND FROM 1979 TO 1986, AND THE LAST FROM 1986 TO DATE.

STARTING BACK IN 1975, THE NATURAL GAS PRICING AGREEMENT ACT BETWEEN ALBERTA AND OTTAWA WAS SIGNED, WHICH BASICALLY SET, ON A PREDETERMINED SCHEDULE, THE ALBERTA BORDER PRICE (I.E. GAS COULD NOT LEAVE ALBERTA AT ANY PRICE OTHER THAN THE ALBERTA BORDER PRICE). GAS AT THAT TIME WAS TIGHT; SECURITY OF GAS SUPPLY THROUGHOUT CANADA WAS VERY MUCH OF A CONCERN.

ALL OF CU GAS' RESERVES UNDER LONG TERM CONTRACTS, PRICED AT 16¢/MCF WITH 1/4¢/YEAR PRICE ESCALATION, WERE OPENED UP AT THE PROVINCIAL GOVERNMENT'S DIRECTION AND OUR PRICES WERE BASICALLY SET AT THE ALBERTA BORDER PRICE OR AS SHOWN THEY WOULD BE VERY CLOSE TO THE AVERAGE ALBERTA FIELD PRICE.

ALL MAJOR PURCHASES, INCLUDING WGML, PAN-ALBERTA, A&S AND OURSELVES WERE ACTIVELY CONTRACTING FOR NEW SUPPLIES IN THE 1975 TO 1977 PERIOD. EXPLORATION WAS AT AN ALL TIME HIGH.

SECURITY OF SUPPLY WAS REALLY THE NAME OF THE GAME AND THE ALBERTA GOVERNMENT, THROUGH THE ENERGY RESOURCES CONSERVATION BOARD ENSURED THAT 30 TIMES ALBERTA'S MARKET REQUIREMENTS WERE SET ASIDE AND

HELD BY PRODUCERS BEFORE GAS WAS PERMITTED TO LEAVE THE PROVINCE.

THEN, IN LATE 1977 AND 1978, WITH THE FLURRY OF GAS CONTRACTING, THE INCREASING PRICE AND THE INCREASED DRILLING INDUSTRY ACTIVITIES, AND A RELATIVELY FINITE MARKET, WE FOUND OUT THAT WE WERE OVER SUPPLIED.

AS THE SURPLUS OF GAS, OR BUBBLE, GREW THROUGHOUT NORTH AMERICA, A NUMBER OF CU GAS' LARGE INDUSTRIALS, AS CONTRACTS EXPIRED, CHOSE TO PURCHASE THEIR GAS SUPPLIES DIRECTLY FROM PRODUCERS OR BROKERS AT PRICES THAT ARE SHOWN BY THE SHADED AREA.

WE AT CU GAS COULD NOT COMPETE TO RETAIN THESE INDUSTRIALS, AS WE HAD OUR CONTRACTS FIXED AT THE ALBERTA BORDER PRICE OR THE AVERAGE FIELD PRICE.

MANY INDUSTRIALS, AS THEY TIPPED THEIR HATS, SAID WE LIKE YOUR SERVICE, BUT YOUR COST OF GAS IS TOO HIGH.

FORTUNATELY, NOT ALL INDUSTRIALS OR NON-CORE CUSTOMERS LEFT AT THE SAME TIME, SO WE HAD SUFFICIENT FLEXIBILITY IN OUR GAS SUPPLIES TO AVOID TAKE-OR-PAY WITH OUR PRODUCERS.

CU GAS BECAME A TRANSPORTER OF THESE INDUSTRIALS' SUPPLIES..., COMMENCING BACK IN 1977 TRANSPORTATION WAS NOT A SERVICE OFFERING IN OTHER CANADIAN JURISDICTIONS UNTIL DEREGULATION OF 1985.

LASTLY ON THIS CURVE YOU CAN SEE IN 1987 THE ALBERTA GOVERNMENT'S FINANCIAL SUPPORT OF RESIDENTIAL AND COMMERCIAL CUSTOMERS ENDED AS THE FIELD PRICE CAME DOWN.

* AGAIN, LOOKING BACK ONE CAN SEE HOW ALBERTA'S DEMAND FOR GAS HAS CHANGED OVER TIME.

THE RESIDENTIAL/COMMERCIAL CONSUMPTION HAS CHANGED WITH THE GROWTH OF THE PROVINCE, COUPLED WITH INCREASING CONSERVATION.

THE ALBERTA INDUSTRIAL MARKET HAS GROWN WITH THE RAPID INCREASE IN THE LATE 1970'S DUE TO THE DEVELOPMENT OF THE PETROCHEMICAL INDUSTRY IN THE PROVINCE AND THE START UP OF TWO MAJOR FERTILIZER PLANTS. THE OTHER CATEGORY IS FOR E.O.R. SHRINKAGE AND PIPELINE FUEL.

THE EX-ALBERTA MARKET IS NOTED AT SOME 1900 PJ IN 1987, ALMOST FOUR TIMES THE ALBERTA RESIDENTIAL, COMMERCIAL AND INDUSTRIAL MARKET.

* WE CAN SEE HOW THE INDUSTRIAL SUPPLIERS HAVE CHANGED OVER THE PAST TEN YEARS, AGAIN DUE TO SURPLUS GAS SUPPLIES AND OUR COMPANIES' NON-COMPETITIVE GAS COSTS. CU GAS, COMMENCING IN 1979, BEGAN LOSING INDUSTRIAL MARKET TO OTHERS AND BECAME A TRANSPORTER.

THE QUESTION MARK BEYOND 1988 IN THE INDUSTRIAL CATEGORY IS WHAT WILL HAPPEN TO THE REMAINDER OF OUR INDUSTRIAL SALES MARKET WITH FUTURE DEREGULATION (CURRENTLY SERVE 13%).

MORE CRITICAL NOW IS THE RESIDENTIAL AND COMMERCIAL SECTOR AND WHAT WILL HAPPEN TO OUR SALES IN THESE CATEGORIES BEYOND 1988. ANOTHER QUESTION MARK (CURRENTLY SERVE 85%).

* SINCE NOVEMBER OF 1985, WHEN THE AGREEMENT ON NATURAL GAS MARKETS AND PRICES, CU GAS HAS BEEN INVOLVED IN A NUMBER OF HEARINGS AND INQUIRIES IN AN ATTEMPT TO DETERMINE WHAT THE NEW RULES WILL BE RESPECTING OPEN ACCESS AND CHOICE OF SUPPLY.

* SOME PROGRESS HAS BEEN MADE:

* CU Gas' field price for long term supplies has dropped from the support level of approximately $1.82/GJ to approximately $1.63/GJ.
* Cu Gas' transportation offerings on their transmission systems have been expanded from 20 year to 1, 2, 3 and 20 years for non-core customers.
* The ERCB has revised its mandated surplus from a 30A to a 15C, "A" standing for total Alberta Markets and "C" standing for core markets, releasing approximately 12 Exajoules or Tcf more gas for export.

* An inquiry held a year ago by the ERCB/PUB dealt with a great number of things, with the primary issue dealing with what security of supply is required by those serving the core market. The recommendation to the Alberta Government was for long term 10-15 years, with the final decision pending.

* Currently we are involved in a hearing before the PUB regarding CU Gas expanding their T-service to industrials or non-core customers located on the Companies' distribution system.

Suffice to say that similar type hearings and inquiries have been held in other Canadian jurisdictions, and the most recent Ontario Energy

BOARD REPORT STATING ALL CUSTOMERS, BOTH CORE AND NON-CORE CUSTOMERS SHOULD HAVE A MINIMUM THREE YEAR ROLLING GAS SUPPLY LEAVES ALBERTA AND ONTARIO FAR APART.

ALBERTA WILL NOT PERMIT GAS TO FLOW OUT OF ALBERTA TO EASTERN CANADA CORE MARKETS UNLESS THEY HAVE A 10 YEAR SUPPLY.

* THE EAST-WEST SAGA GOES ON AND UNTIL THERE IS SOME RESOLUTION REGARDING THE SECURITY OF SUPPLY ISSUE, THE $64,000 QUESTION REMAINS UNANSWERED.

AGAIN, AS NOTED BEFORE, WE HAVE AN OBLIGATION TO MAINTAIN COMPETITIVE GAS SUPPLY COSTS TO OUR SALES CUSTOMERS, BUT UNTIL THE PRICE AND SECURITY OF SUPPLY ISSUES RESPECTING OUR CORE CUSTOMERS IS SORTED OUT, AND WHO REMAIN AS SALES CUSTOMERS, CU GAS CANNOT PRACTICALLY DETERMINE ITS GAS SUPPLY CONTRACTING STRATEGY AND CANNOT DETERMINE ITS OPTIMUM GAS SUPPLY PORTFOLIO.

* CU GAS' GAS SUPPLY PORTFOLIO CONSISTS OF: 63% OF ITS SUPPLY FROM PRODUCERS UNDER LONG TERM CONTRACTS, 8% FROM THEIR OWN EXPLORATION AND DEVELOPMENT EFFORTS, 5% FROM SYSTEM SUPPLIERS SUCH AS WGML, PAN-ALBERTA, A&S, 2% FROM SALT CAVERN PEAKING AND 3%

FROM UNDERGROUND STORAGE, AND 19% FROM SHORT TERM OR SPOT PRODUCERS AND BROKERS.

IF WE ARE REQUIRED TO HAVE A NOMINAL VOLUME UNDER CONTRACT TO COMPLY WITH THE SECURITY OF SUPPLY REQUIREMENTS, OUR CURRENT CONTRACTED SUPPLIES MAY BE TOO LARGE AND OUR PRICE MAY BE TOO HIGH.

IF WE BELIEVE THE U.S. REQUIREMENTS FOR ALBERTA GAS WILL CONTINUE TO INCREASE AS THEIR SUPPLY AND DEMAND COMES INTO BALANCE, AND GAS PRICES IN ALBERTA INCREASE, THEN WE BEST CONTRACT SOON FOR ADDITIONAL LONG TERM SUPPLIES AS MOST OF THE SHORTER TERM AND AND SPOT VOLUMES WE CURRENTLY BUY, WILL DRY UP.

TO ADD TO AN ALREADY RATHER CONFUSING "FREE MARKET PLACE" WE SUSPECT THAT AS SUPPLY AND DEMAND IN ALBERTA COMES BACK INTO BALANCE, SOME OF THOSE CUSTOMERS WHO HAVE LEFT US OVER THE PAST 10 YEARS WILL WANT TO RETURN AND CU GAS WILL AGAIN HAVE TO ADAPT AND REVISE THEIR GAS SUPPLY PORTFOLIO TO ACCOMMODATE THESE NEW CUSTOMERS.

* THE FUTURE... WHO KNOWS FOR SURE? BUT I CAN GUARANTEE EVERYONE THAT TIMES WILL NOT BE BORING.

UNFORTUNATELY WITH DEREGULATION AND A NEAR MATURE MARKET WITHIN ALBERTA AND SURPLUS SUPPLIES, THE GAS SUPPLY PIE HAS NOT GROWN, BUT THE EXISTING PIE IS MERELY BEING REALLOCATED TO NEW SUPPLIERS. PRICES ARE DOWN AND THE ALBERTA GOVERNMENT COFFERS ARE BEING DEPLETED.

THE FUTURE... WHO KNOWS? BUT IF HISTORY REPEATS ITSELF, AND IT GENERALLY DOES, THE SHORTAGE... OR PERCEIVED SHORTAGE OF 1975, WILL AGAIN BE ON US AND SECURITY OF SUPPLY RATHER THAN PRICE WILL BE PARAMOUNT IN EVERYONE'S MINDS.

* I BELIEVE THE FUTURE ALBERTA NATURAL GAS INDUSTRY WILL BE BRIGHT, BUT IT MAY BE TWO OR THREE MORE YEARS BEFORE WE SEE THE FLAME GROWING LARGER, AND A COLD WINTER THROUGHOUT NORTH AMERICA WOULD SURE HELP IN RATIONALIZING THE SIZE OF ALBERTA'S SURPLUS SUPPLIES.

GAS MARKET CHALLENGES: BRITISH COLUMBIA

Presented by

Arthur H. Willms

Executive Vice President and Chief Operating Officer

Westcoast Energy Inc.

Vancouver, British Columbia

Canada

SYNOPSIS

The Gas Challenge of British Columbia is to gain access to the California market while increasing consumption in the traditional markets of British Columbia and the U.S. Pacific Northwest.

British Columbia gas has traditionally served the province's domestic market and up to 70 percent of the market of the U.S. Pacific Northwest. These markets are relatively mature, although opportunities are being pursued within them.

The Vancouver Island Pipeline project would increase B.C. gas production by 10 percent. Small increases on many fronts - hot water heaters and NGV conversions, for example - will eventually add up to significant volumes. Ethane-based petrochemical production could create an additional demand of 15 Bcf per year.

But large new markets will have to be gained south of present markets - primarily in California.

California needs B.C. gas to increase its diversity of supply. It needs diversity of supply to gain the best energy security and price. As California clean air legislation is strengthened this need will increase, but improvements to pipeline infrastructure will be required in order to facilitate the B.C. connection with California markets.

Pipeline capacity already exists to the U.S. border through Westcoast's mainline and across Washington State through Northwest Pipeline's system. Still needed is the last link into California - for example, an expanded PGT line or a new project such as the Kern River transmission pipeline.

These projects will be a challenge, but the question is rightly asked: does it make sense to invest capital to reach proven young production regions, or dying fields with the potential of much higher finding costs?

GAS MARKET CHALLENGES

Presented by

Norman B. Loberg

Vice President, Marketing

The Consumers Gas Company Ltd.

Toronto, Ontario

Canada

At

The Seventh Annual CERI

International Oil and Gas Markets Conference

September 18-20, 1988

Convention Centre

Calgary, Alberta

Thank you for the invitation to talk about the challenges and opportunities for natural gas distributors.

Today, distributors find themselves in a state of radical change and that change has been brought about by deregulation. In the final analysis, however, the specific challenge remains the same: Market Share and Growth.

As the last link in the production and supply chain of natural gas -- when distributors achieve their objective of increased market share and growth, the producers and pipeline operators will also benefit.

Thus, the challenge of Market Share and Growth is not exclusive to the distributor, it is an objective common to us all.

It is true, we have had, and will likely continue to have, different perspectives of the market and it's needs.

Even so, we must recognize our dependency on each other, and our collective need to satisfy the ultimate arbiter; the customer.

As one wise marketer once said, "If the shoe fits... you're not allowing for growth".

Let us accept, then, that we have a common objective: to enhance the position of natural gas in Existing and Future Energy Markets.

My Company's operating area provides an excellent illustration of the many factors which present an ongoing challenge in the marketing of natural gas.

In 1955, at the end of the manufactured gas era, Consumers Gas served about 155,000 customers with annual volumes of around 5 Bcf.

Consumers Gas, Canada's largest distribution utility, is now serving nearly one million customers in south central and eastern Ontario, Western Quebec and Northern New York State. In fiscal 1988, Consumers will deliver approximately 350 Bcf to it's customers.

That ranks Consumers as the fourth largest distributor of natural gas in North America, in terms of total sales volume.

Without doubt, we, along with the other Ontario distributors and our customers, have greatly benefitted from the increased availability of Western Canada's natural gas.

Aggressive marketing and security of supply has combined for real market growth.

It is equally obvious that our upstream partners have also benefitted as a result of the growth of the natural gas market in Ontario.

Ontario typically accounts for about 40 percent or over 730 Bcf of domestic sales annually. This is the equivalent of around 80 percent of Canada's average annual exports over the past four years.

Despite considerable, and ongoing competition from alternate energy sources -- primarily fuel oil and electricity -- natural gas has enjoyed a virtually unbroken pattern of growth in Ontario over the past three decades.

It was marketing guru, Theodore Levitt, currently editor of the Harvard Business Review who said:

> "In truth, I believe there is no such thing as a growth industry. There are only companies organized and operated to create and capitalize on growth opportunities. Industries that assume themselves to be riding some automated growth escalator invariably descend into stagnation".

I like to think that our industry is organized and operated to effectively capitalize on growth opportunities.

In Consumers marketing area, we continue to face substantial competition from heavy fuel oil in the industrial and large volume commercial markets. The other Ontario distributors face similar competition.

In fact, over the past several months, substantial volumes of natural gas have been displaced in Ontario, as some of our large Industrial customers acquired lower priced heavy fuel oil.

We expect no let-up from H.F.O. competition in industrial and commercial markets. This view is predicated on the prospect of continued instability in international crude oil supply/demand and the resulting impact on the prices of petroleum products.

Electricity, always a high profile energy source in Ontario, is likely to become the principal competitor during the short to mid-term future, as generating and transmission problems in the province are resolved.

It is also a reality that Ontario Hydro plans a renewed emphasis on energy management promotions to all customers including residential. As this strategy was only recently adopted, it is too early to gauge the extent of any impact on the position of gas in our service territory.

In addition, Hydro is introducing such innovations as time of use rates, complemented by the promotion of technological advancements in electric equipment. These initiatives, plus attractive financial assistance programs, will enhance electricity's formidable, competitive position.

We did not achieve our present market position by accident. We have been aggressive marketers. And our experience tells us that the continued growth of the natural gas industry in Ontario will require a pro-active response to each new challenge.

To a marketer, challenge means opportunity and, in our perception of the future, we can see opportunities to consolidate and expand our position.

I'd like to summarize some of the influences which will have an impact on the marketing of natural gas. Although I speak from an Ontario perspective, I believe you will see a similar effect on both the national and international marketing scenes.

As our industry continues to adjust it's operations to facilitate a more open market, the main influence is deregulation itself.

Deregulation has changed the traditional role of the utility. Reregulation, as I like to call it, has cast a new light on our activities and we are spending even more time with the regulators.

In fact, many of us have had to add additional resources to cope with the increased workload and paper burden.

Progress has been made toward the establishment of a market responsive system. However, the concept of full access to supply, transmission systems, distribution systems and price, has yet to be achieved.

The basic role of Consumers Gas has been, and will continue to be, the owner and operator of a gas distribution system which links the various sources of supply with customers in its franchise area.

In fulfilling this role, we will also continue to discharge our responsibility as the long term custodian of the market. In response to the needs of a great majority of our customers, we will operate as a full service supplier while accommodating -- wherever feasible and on an equitable basis -- the specific service needs of individual customers, or groups of customers.

Historically, the regulated environment in which the distributor operated could be characterized as relatively stable and predictable...attributes generally regarded favourably by the public.

However, the distributor's role may well continue to change. It will be far more difficult for us to maintain stability and predictability. Today we are not simply aggressive marketers, we are now facilitators, accommodating the best possible gas purchase and supply arrangements for our customers. This challenge represents a very real opportunity to enhance our position in the energy market.

The Ontario Energy Board has, in its more recent decisions, made it clear that market responsive pricing in Ontario can only be achieved if all customers are given unencumbered access to gas supplies, transmission and distribution systems.

To that end, the Ontario Energy Board has concluded that certain changes to the historical system were necessary in order to make market responsive pricing a reality.

For distributors in Ontario, these changes include the unbundling of services, separation of the distribution and merchant functions within each utility and renegotiation of the agreements signed with Trans Canada Pipelines, and Western Gas Marketing Limited.

In addition, the Board determined that brokers should be allowed to operate in Ontario.

The OEB, in its interim report to the Lieutenant Governor in Council dealing with security of supply, made a number of significant recommendations that could have a serious impact on all of us.

However, let's remember it's an interim report. There is another shoe to drop and, ultimately, a response by the Government of Ontario is required.

It was Bob Martin, C.E.O. of Consumers Gas, who told you at last year's Conference that, with regard to deregulation, "We are still in transition".

A year later, our industry is still in transition. However, in my view, the experience of the past year has helped all parties move closer to a free market for natural gas.

But, as Bob said then, the main areas of concern are fairness and security of supply. And these continue to be our primary concerns. We are still working to gain access to the wholesale natural gas market for all our customers, by creating a portfolio of short, medium and long term supply arrangements.

Nevertheless, the bottom line in this or any other industry, comes down to market share and growth. The more we promote the growth of the total industry, the greater the opportunity for all the players to participate and benefit.

I doubt that any of our industry colleagues or customers would disagree with our motivation -- because we all benefit from increased gas use -- provided the product is competitively priced. And, as we save on the gas we buy, those savings are passed along. This is the tangible benefit to customers under deregulation.

For example, annual savings achieved on behalf of our residential and small commercial customers amount to about 30 million dollars. Our industrial customers have realized savings amounting to about 142 million dollars.

Not every customer has had to buy "direct" to participate in the savings available.

However, distributors still need greater choice and access to the wholesale natural gas market in order to optimize the potential benefits to all customers.

As I have noted, full access is currently inhibited by barriers such as:

- o long term supply contracts;
- o National Energy Board rulings which preclude self-displacement; and
- o certain restrictions imposed by the producing provinces, relative to the removal of gas, to name the more important.

These issues are the subject of ongoing discussions at the federal and provincial government level with input from members of our industry.

I think that the Minister of Energy for Ontario, Bob Wong, probably captured the essence of the problem in a June address in Calgary.

The Minister said that one of the things that makes a market work is security --- Security for the seller, and security for the supplier.

Emphasizing that Ontario is Alberta's best customer, he summed up this way:

- o "Security is one of the fundamental issues (at hand here). The other one is price".

- o "What both Ontario and Alberta want to do is enhance security---Alberta wants secure markets and Ontario wants secure supply".

- o "What we need to do--and what we are working on--is enhancing that security for both of us".

The Ontario distributors, and the other members of our industry, endorse the Minister's view.

Through the Ontario Natural Gas Association, we are providing input and support to the provincial authorities. We hope to assist in the implementation of an equitable supply and pricing system, one that is fair to all parties.

Equitable supply and price does not, in our view, mean the so-called bargain basement approach to commodity pricing.

The ideal situation is a competitive pricing mechanism which will reflect:

1. The value of the commodity;
2. The cost of secure supply; and
3. Will afford fair treatment for the cost of transmission, storage, distribution and ancillary services.

I have no doubt that we will eventually see such a mechanism in place. In the interim, we will continue to act as the facilitator between the producers and our customers to ensure that we optimize the position of gas in Ontario. In effect, providing access to all options for the benefit of all customers is our major goal.

Supply and price aren't the only forces in our marketplace.

To an increasing extent, technological developments are influencing the manufacturing sector of the Ontario market. The widespread use of robotics and the expanded utilization of plastics in the manufacturing industry are illustrations of technical sophistication.

These developments are not seen to pose a threat to the position of natural gas. To the contrary, we regard them as an opportunity.

In our view, the traditional market potential of natural gas, consisting primarily of process, heating and base load applications, can be enhanced through the implementation of specific technologies representing non-conventional use of natural gas.

Although we don't foresee gas operated robotics, or plastics extrusion equipment, we do see an opportunity to use gas to generate the electric power on which they depend.

There are three basic applications worth exploiting:

- Co-Generation - is the combined production of useful thermal energy and electricity from one fuel source in a single process.

- Combined Cycle - is the cascading of two thermo-dynamic cycles to increase the efficiency of fuel use in electric power generation: for example, gas turbine plus steam turbine combinations.

- Select Use - The use of natural gas in a coal fired utility boiler to reduce acid gas emissions through techniques such as co-firing seasonal use, reburn etc.

To illustrate the dimensions of this new market opportunity:

- o We project that incremental gas volumes, approximating 43 bcf, could result from the implementation of natural gas fired co-generation in industrial applications in Ontario.

- o Combined cycle and select use offer even greater potential. For example, the Railway Lands Project in downtown Toronto, one of the larger urban redevelopment projects in North America, could draw on an additional 35 Bcf per year.

- o The combined potential of all these and other innovative electrical generation applications, when implemented, could represent an incremental gas load of 100 to 150 Bcf.

Currently, the Ontario Government's Select Committee on Energy is reviewing the ways in which the province's future electricity demand can be met. These deliberations include both supply and demand options.

The Ontario Natural Gas Association is preparing a brief for submission to the Committee, detailing the ways in which natural gas can reduce peak electricity demand on the province's electricity supply system.

We want to prove that electricity can be produced efficiently...while at the same time helping to clean up the air around us. We feel that the Toronto Railway Lands Project will amply demonstrate our point.

In the policy area, revisions to the Ontario Power Corporation Act, which governs the operation of Ontario Hydro will likely be tabled in the Legislature in the fall of this year.

We hope that these revisions will encourage the development of independent power generation... natural gas being one of the better options, of course.

Success will be measured by how well we obtain secure and competitively priced volumes of natural gas supplied on a long-term basis.

We recognize that the capital investment involved requires extended amortization. That's why we cannot expect major investment without a firm commitment by the producers, transmitters, distributors and the end-users over the long term.

We are also looking confidently towards the promising motor vehicle fuel market.

Of major significance is the valuable contribution natural gas can make in reducing environmentally damaging emissions.

This advantage of natural gas over conventional vehicle fuels is probably our best response to the ongoing public debate over diesel and gasoline exhaust pollution.

Extraordinary efforts promoting the concept of NGV have been undertaken by both the private and public sectors; efforts which have placed Canada in the vanguard of this emerging industry, particularly in the field of urban transit.

In Ontario, there are four municipal transit authorities who are operating natural gas fueled buses.

Toronto, which operates the largest mass transportation system in Canada, has recently made an initial commitment to natural gas. At present, the TTC has 25 NGV buses on order with a longer range commitment to 125.

The NGV program can, through the development of a unique manufacturing base in Canada, create new job opportunities and a new technical infrastructure for the country. The recent production of original equipment Natural Gas buses by Ontario Bus Industries for Brooklyn Union in New York attests to our new-found capability.

Field testing of the Sulzer home compressor is well underway with very promising early results. Just imagine the benefit of doubling the gas load for every residence when householders can refuel their cars overnight at home.

In conclusion--one last thought--let's keep in mind that there will be increasing pressure by the environmentalists -- against the use of fossil fuels to meet our energy needs.

We must take care that natural gas is clearly differentiated from all the other fossil fuels.

Clean air and natural gas. We're still part of the pollution solution.

THE OUTLOOK FOR PETROLEUM EXPLORATION IN THE THIRD WORLD

Abstract
of presentation at the

Seventh CERI International
Oil and Gas Markets Conference
Calgary, Alberta, Canada

September 18-20, 1988

by

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World Bank

THE OUTLOOK FOR PETROLEUM EXPLORATION IN THE THIRD WORLD

Over the coming decade the attractiveness of petroleum exploration and development in third world countries will be governed by three important factors:

1. the price of petroleum products which will be a function of the demand of the developed countries,

2. the costs of exploration and development in developing countries, and

3. the growing markets in the developing countries.

Let us look at each of these factors in turn.

The World Petroleum Market in the 1990's

Through the decade of the 1990's (and well beyond) the demand for petroleum products on the part of the developed countries will continue to be the dominant factor in determining prices and subsequent supply responses. Demand is growing rapidly in developing countries but it is still too small to effect world prices. Demand is expected to grow at rates of about one percent in OECD countries. Alternatives to oil, particularly coal and gas, will limit the ability of oil producers to extract increasing rents over time.

Developed countries will continue to support their own industries and to encourage production in non-OPEC areas. Some upward pressure on prices is likely in the mid-nineties but in real terms these price increases will be relatively modest and prices are likely to return to the long term average shortly after the turn of the century.

The Costs of Exploration and Development

Given the modest expectations for price increases, the attractiveness of exploration in developing countries will depend on the combination of costs and expected rates of return. Developing countries have traditionally been viewed as high cost producers. Some of this is because of the accidents of geology but much of it is because of inadequate physical and institutional infrastructure. The increasing priority given to improving export earning is forcing countries to take remedial measures to deal with both the infrastructure and institutional factors. The scarcity of capital will encourage these countries to look towards the international capital markets for the bulk of their resources which in turn will require the offering of adequate rates of return to investors. With rising costs and limited opportunities in the developed countries, investors will increasingly be looking to the developing world for new supplies.

Market Growth in Developing Countries

By the end of the next decade most of the increase in petroleum demand will come from the developing countries. It is also likely to be the most profitable part of the market. At present and projected prices, provided measures are taken to control costs, substantial rents can be generated in most countries. Governments, whether to promote exports or encourage import substitution, will be prepared to forego some of these rents and to protect domestic production, thereby offering attractive terms to international capital willing to invest in these markets. Some of the larger countries, in particular, are likely to be attractive areas for foreign capital. The use of gas for domestic power production will be a growing part of this market.

The World Bank's Role

The Bank is unlikely to be heavily involved in funding either exploration or development. Given the risks involved, countries are better off seeking equity rather than loan capital. The Bank's efforts will be focused on improving the investment climate through improvements in infrastructure, information, and the legal framework. The Bank's new agency, the Multilateral Investment Guarantee Agency (MIGA), can assist, for example, through coverage of some of the political risks.

In the case of natural gas where the primary market is domestic power generation, the Bank is prepared to invest but given both the large capital requirements and the technical skills involved, the Bank is encouraging countries to seek partnerships with external capital.

OIL AND GAS POLICY AND PROSPECTS TO 2005 - NORWAY

Abstract
of presentation at the

Seventh CERI International
Oil and Gas Markets Conference
Calgary, Alberta, Canada

September 18-20, 1988

by

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ODD SVERRE HARALDSEN
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"OIL AND GAS POLICY AND PROSPECTS TO 2005"

1. Introduction

I have been invited to speak about the directions being taken in Norway regarding (i) long-term energy planning, (ii) the role for energy within the broader economic and social planning objectives and (iii) the role for oil and gas within this energy planning.

What I intend to do is to give a short description of Norway as an "energy country". Then I will deal with the structure of Norways domestic energy balance and with the long term objectives for our domestic energy policy. In the latter part I will bring forward some specific issues related to the oil and gas sector.

2. Norway as an energy country

While a large part of the world have shortage of energy and thus are occupied with long term supplies, we in Norway are interested in finding ways of disposing of our energy resources. Norways energy resources consists of hydropower and oil and gas. With its 4 million people Norway has a primary energy consumption per capita which are more than twice the average in Western Europe or about 8 toe.

The final consumption of energy consists of 10 % solid fuels, 47 % petroleum products and 43 % electricity of which approx. 100 % is based on hydro power.

The industrial sector consum about half of all energy delivered (and half of the electricity consumption). Thus, it is a fact that energy has been the key to the development of Norwegian power intensive industries which is an important part of our industrial structure.

To complete the picture of Norway as an energy country it is necessary to compare the energy consumption with our production. The energy production is today close to 4 times final energy consumption which makes Norway an important exporter of oil and gas.

3. Future developments in domestic energy consumption and supplies.

Future energy consumption will depend on a lot of uncertain factors like economic growth, energy prices and technological developments. We have in our latest forecast assumed annual economic growth to 2000 to be 2.1- 3 per cent. We have also used two scenarios for crude oil prices which give $20 and $30 (1986-usdollars) in 2000 respectively. In our main (moderate) alternative we have used low economic growth and the high crude price scenario. This will increase our energy consumption by 1.7 per cent pr. year to about 22 mill. toe in 2000. The consumption of petroleum products will increase by 1.9 per cent yearly due to competitive prices compared to the alternatives.

For onshore economic activities the electricity is very important. Electricity demand is expected to increase to 124 TWh in 2000 from about 100 TWh in 1987. This includes 36 TWh for power intensive industries and a key issue is whether these industries will need this power at the assumed prices. How much these industries will demand will be decisive for contruction of new electricity capacity.

So far all electricity is based on hydro power. With increasing costs of electricity based on hydro power and access to natural gas in large quantities at our continental shelf we are now in a new position. It is now possible that the next main additions to our electricity capacity will be based on natural gas. This is definitely the main policy issue on our domestic scene.

Regarding our energy policy objectives one primary objective is to bring forward energy supplies at lowest cost possible for the society. Further, the energy prices is the best instrument to promote efficient and rational use of the energy resources. The price paid should reflect the society's cost of providing more energy. This has been underlined by the government and will be a main guideline for the future energy policy.

Introducing gas in the Norwegian energy balance in the 1990'ies will not change these principals.

Energy - and hydro power electricity in particular - has been and will continue to be important for mainland Norway well into the next century. Further, during the next 10-15 years there will be established a linkage beetween our petroleum activities offshore and the domestic energy scene through use of natural gas.

4. The oil and gas sector

Until the beginning of the 1980s, the discussion concerning the extent of the petroleum activities mainly focused on production measured in millions of tons of oil equivalents (mtoe). Instead of adopting such a production figure as the basis, the Government finds it more expedient to consider the rate or pace of production in connection with a number of social objectives. The most important are:

- The Norwegian economy must also in the future be based on a diversity of trades and industries, even if oil revenues were to assume large proportions.

- Other trades and industries must be given satisfactory conditions for growth parallel to the development of the petroleum sector.

- The petroleum industry should form a basis for development of competitive industries.

- Decisive weight must be ascribed to evaluations of profitability and commerciality in the choice of development strategy.

- Foreign policy aspects.

- Great emphasis must be ascribed to safety issues and environmental considerations.

- Impacts on social and regional aspects must be evaluated.

Before looking into the future I would like to remind you of the economic importance of the petroleum sector to our economy. In 1987 the sector amounted to 12 % of GNP, 28 % of total exports and 10 % of total state revenues. However, it only employed 0.5 % of the work force directly.

In 1987 the production was 49 mtoe of oil and 28.9 mtoe of gas. Future developments depend on reserves, prices, cost efficient technology and many other factors. The primary policy objective is to have the petroleum resources developed in accordance with our economic interests. This means that it also is of interest to us with some stability in prices and investment levels.

Regarding prices it is the Norwegian Government's view that stable prices at a reasonably high level is in the long term interest of both consumers and producers.

When looking into the future it is natural to start with the reserves. In the "bank" we have somewhat less than 5 billions toe. Most of this is in the North Sea. Outside Mid-Norway about 500 mill. toe oil and gas is proven and outside Northern Norway about 250 mill. toe - mainly gas - has been found. With todays production levels and reserves we can produce gas for more than 100 years, but oil only for 30-35 years. In the North Sea we have decided to develop more than half of the expected resources. Of the remaining proven resources a major part is natural gas.

On the other side there are limited markets for new gas developments. Thus, the challenges for the oil companies and authorities alike could be formulated very simple: find oil and sell gas! This is necessary if Norway shall continue as a petroleum country after the turn of the century.

To increase our reserves - preferably of oil - we are following a geografically diffentiated exploration strategy.

Based on decisions already taken the future production profile will show a decline from the early 1990's. Thus, new projects will have to be decided upon if we are to keep up the production levels reached in the early 1990's.

However, development of the fields according to the plans of the companies will mean that all major oil fields will be decided upon within the next 2-3 years. This will increase the investment levels in the early 1990's to an unacceptable high level which it will not be possible to maintain further into the 1990's. Thus, the government will postpone certain oil field developments so as to stretch the investments and thus the oil production into the next century. This will delay oil production to a period when the market may be in need for more oil.

The policy of stretching the investments will mean that some projects will be delayed in the years to come.

Also the state's risk exposure - through direct ownership in fields and the tax system - will be an important issue in the coming years. It is desirable not to be too dependent on the petroleum revenues and the risks through swinging revenues.

Since gas also is very important in our exports of petroleum products I would like to mention that Norwegian natural gas covers about 12-13% of the consumption in Western Europe. At the continental Europe the Federal Republic of Germany, France, the Netherlands and Belgium are our most important customers through long term contracts. For these countries new contracts have been signed that will extend the deliveries well into the next century. This is based on the large Troll-field. Before 2000 there seems to be limited possibilities for new natural gas deliveries to these markets. However, also the southern European markets (Spain and Italy) are within reach of Norwegian natural gas.

United Kingdom has also been a long term customer of Norwegian gas, but so far no new contracts covering the period after the early 1990's have been signed.

In the longer term we also view the United States as an interesting gas market. Development of gas prices in the US and the cost of supplying LNG will decide whether Norwegian natural gas will be delivered to this market in the next century.

For Norway it is also a need for secure outlets of our crude oil production. This is of course a commercial matter. There has been a trend among oil producers to go downstream. I dont think this trend has stopped and we will see more towards 2005. So far Norwegian companies are established downstream in Sweden and Denmark and are looking at projects in Federal Republic of Germany.

5. Concluding remarks

A main concern to policy makers in Norway is to integrate the energy sector into our economy without being to dependent on one particular sector. Our industry has been very power intensive and that has exposed our economy to international developments. The same applies to our petroleum sector which are even more important to our economy. Hopefully we will be able to cope with the uncertainties in oil and gas developments so we can enjoy the economic benefits.

OIL AND GAS POLICIES AND PROSPECTS IN BRAZIL - FROM PRESENT TO 2005.

Presented by
Milton Romeu Franke
General Manager of Exploration
Petrobrás (The State Oil Company of Brazil)
Rio de Janeiro, RJ
Brazil

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The Seventh Annual CERI
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A. Introduction

Brazil admittedly is well endowed with natural resources, but has imported considerable amounts of energy sources, mainly petroleum. However, the time series of energy consumption and production have shown favorable trends, and there is an expectation of significant oil imports reduction in the near future.

In this speech I will summarize the evolution of energy consumption, the oil and gas production, and the perspectives of future petroleum production in Brazil.

B. Retrospective

Until the first petroleum price shock at the end of 1973, the abundant oil supply in the international market, linked with the availability of domestic alternative energy resources, caused Brazilian economy to rely mainly on the use of petroleum and hydroelectricity. The biomass played a secondary role (Figure 1).

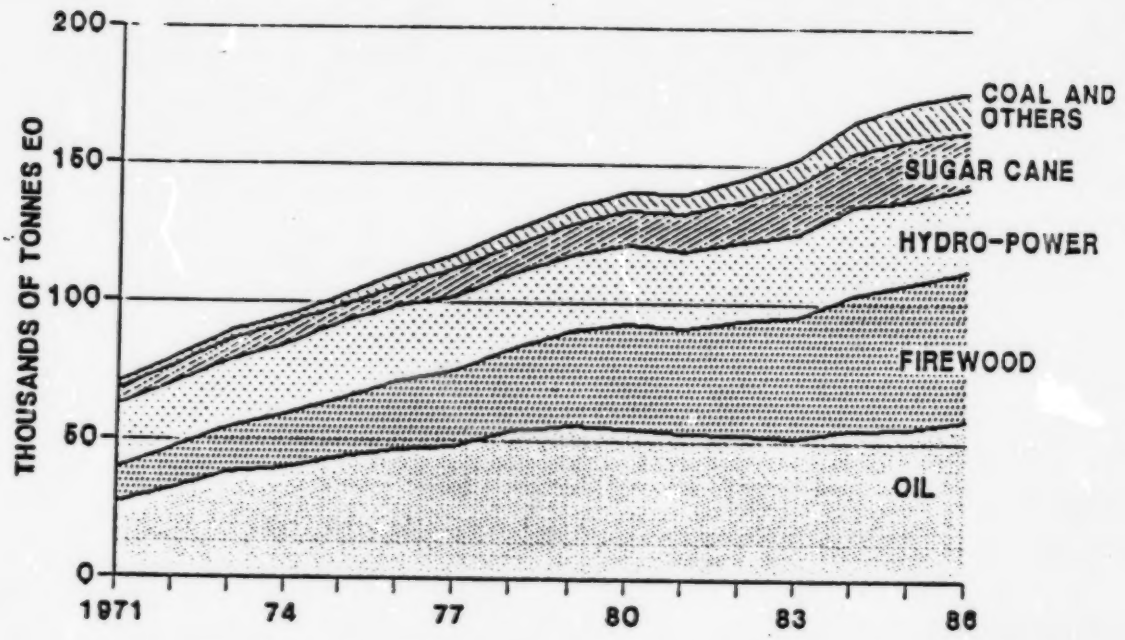

Figure 1: Time series showing evolution of primary energy sources consumed in Brazil.

From 1945 to 1973, the oil share of Brazilian demand for primary energy sources increased from 17% to 43%. In 1973, the petroleum consumption reached 787,000 barrels a day, of which 78% were imported **(Figure 2).**

Given the Nation's high dependence on foreign petroleum sources, the oil price shocks have caused an increasing expenditure of foreign currency. Consequently, Brazil's trade balance has been severely impacted **(Figure 3).**

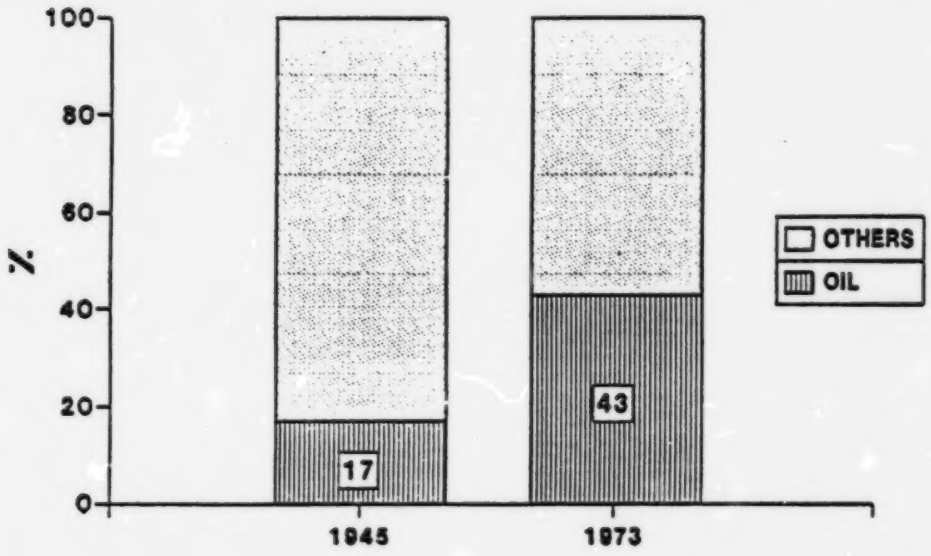

Figure 2: Shifting of petroleum share of Brazil's energy source matrix.

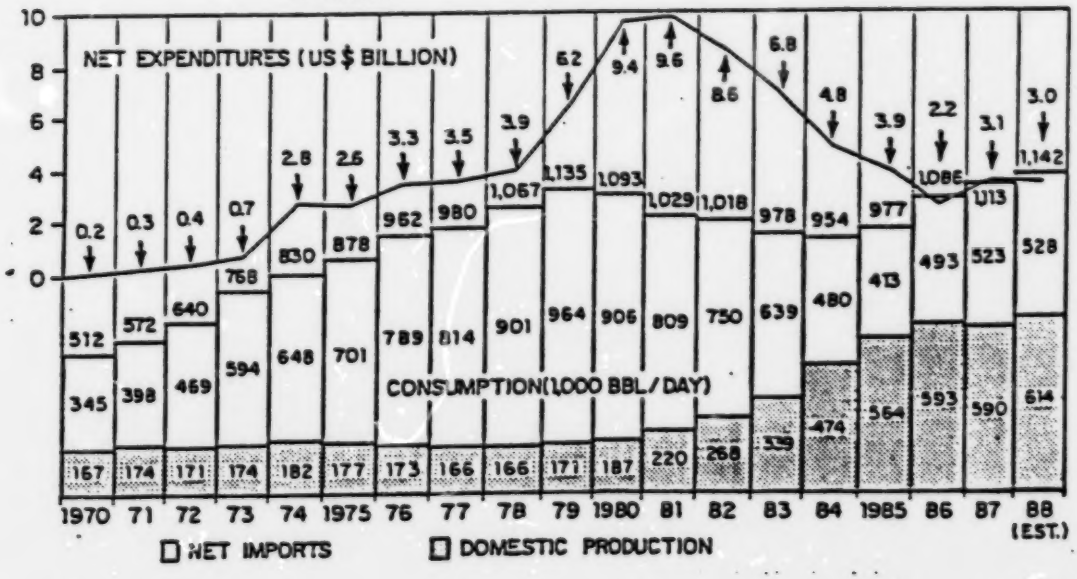

Figure 3: Evolution of both petroleum import expenditures and petroleum consumption in Brazil.

The economic crisis has forced the reorientation of the energy policies, and has accelerated some solutions that were adopted before 1979, such as the "National Alcohol Program". Aiming at the reduction of both the dependence on foreign oil and the net expenditure of foreign currency, a policy has been adopted which (1) emphasizes the activities of petroleum exploration and production, (2) encourages energy conservation, and (3) promotes the replacement of petroleum products by alternative products.

C. Oil and gas production in Brazil

The Brazilian sedimentary basins, with various degrees of attractiveness for petroleum exploration and production, are shown in **Figure 4.** The aggregate of such basins covers approximately four million square kilometers, one of the most extensive sedimentary areas in the world.

Among all Brazilian basins, the Campos Basin is outstanding as the nation's major petroleum province. It produces over 350,000 barrels of oil plus NGL per day (1987 average), and includes the recent and promising discoveries of the first giant fields of the country **(Figure 5).**

Oil and gas production in Brazil increased about 270% from 1979 to 1988, according to **Figures 6 and 7.** Such an increase is a significant achievement for Petrobrás, given the adverse economic constraints faced by the Nation.

Figure 4: Geographic distribution of Brazilian sedimentary basins.

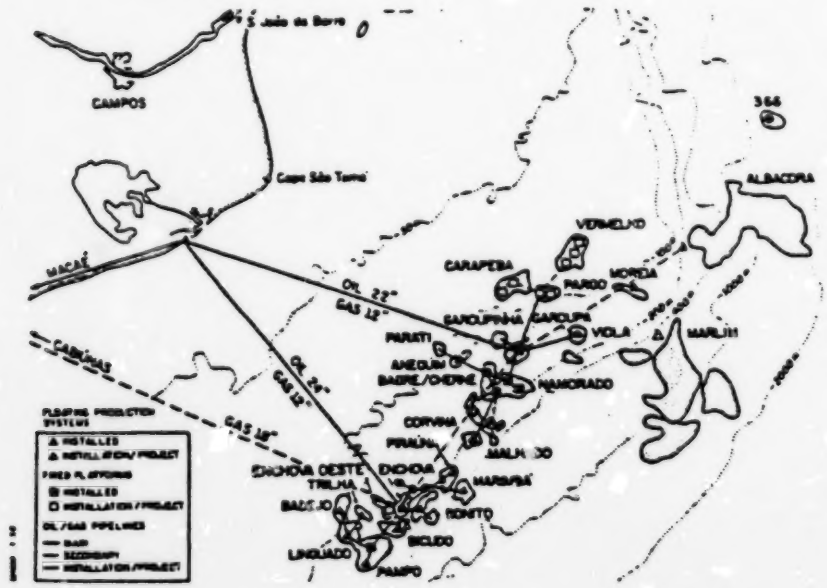

Figure 5: Campos basin, offshore Rio de Janeiro State, represents the major petroleum province of Brazil.

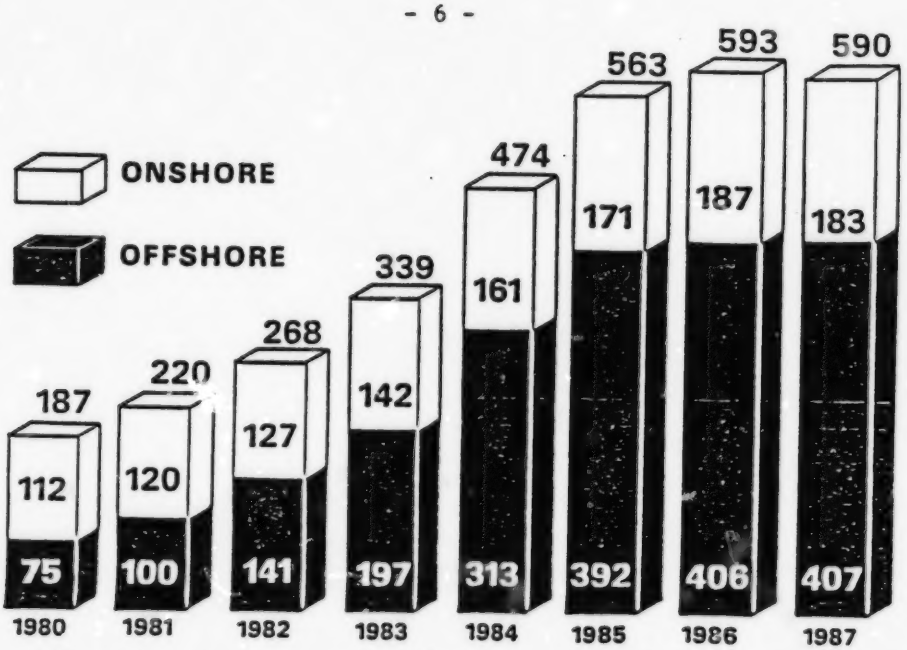

Figure 6: Oil plus NGL production in Brazil (thousand barrels per day).

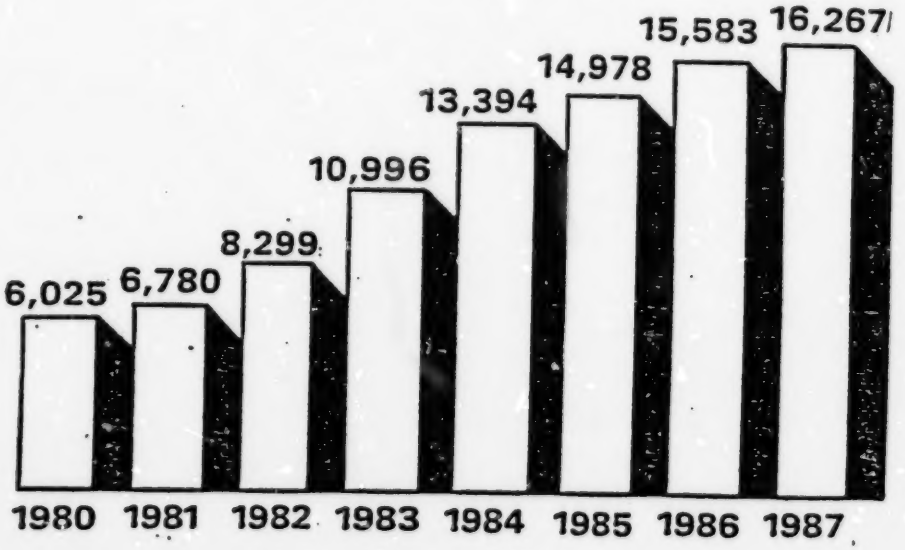

Figure 7: Natural gas production in Brazil (thousand cubic meters per day).

Despite the expressive increase in production, as shown in previous figures, Brazilian oil and gas reserves also have been increasing, doubling in a ten-year period, as shown in Figure 8. It is worth noting that, if deep-water reserves were included, over three billion barrels would be added to the reserves estimated at the end of 1987.

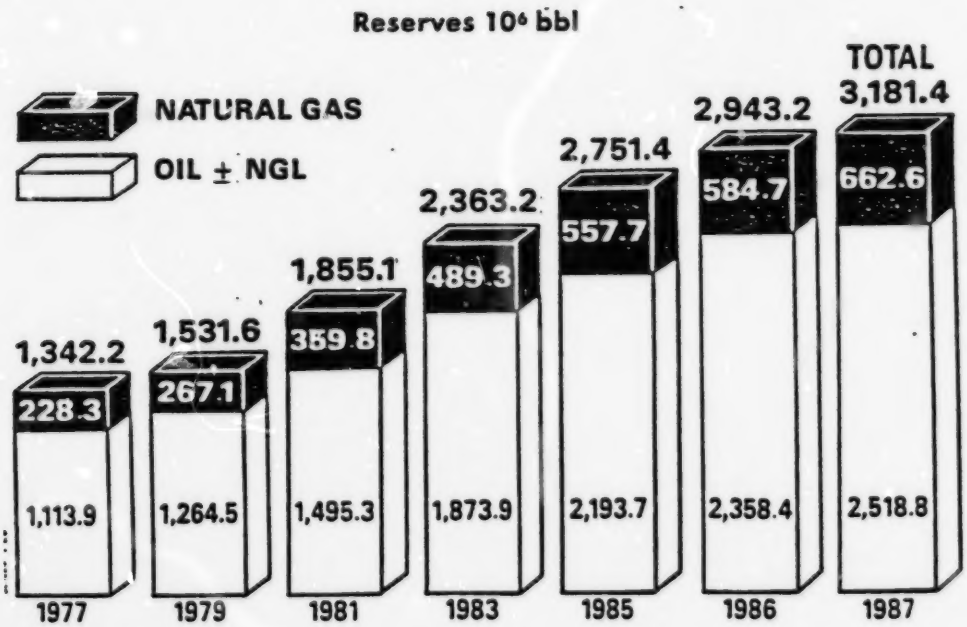

Figure 8: Growth of petroleum reserves (million barrels). Gas reserves shown as oil equivaient.

It should be emphasized that the growth in both the production and the reserves of Brazilian petroleum stems from the exploration effort, mainly offshore, and from the achievement of some technological break-throughs.

Petrobrás' accomplishments should be evaluated not only from the previously shown results, but also from some records (**Figure 9**) and from the know-how acquired in developing deep-water production systems (**Figure 10**).

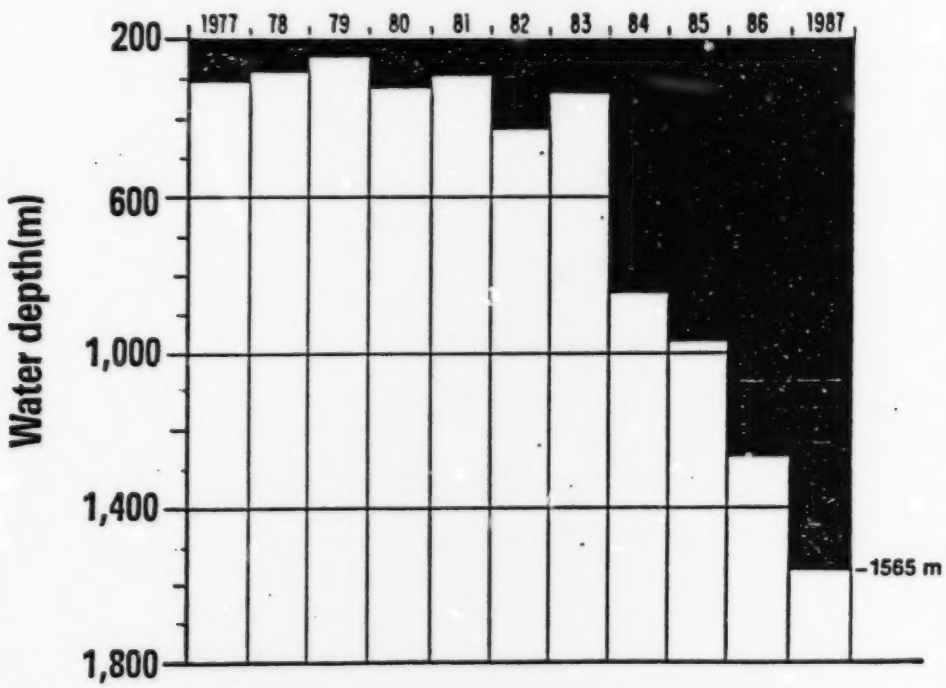

Figure 9: Maximum water-depth of wells drilled by Petrobrás.

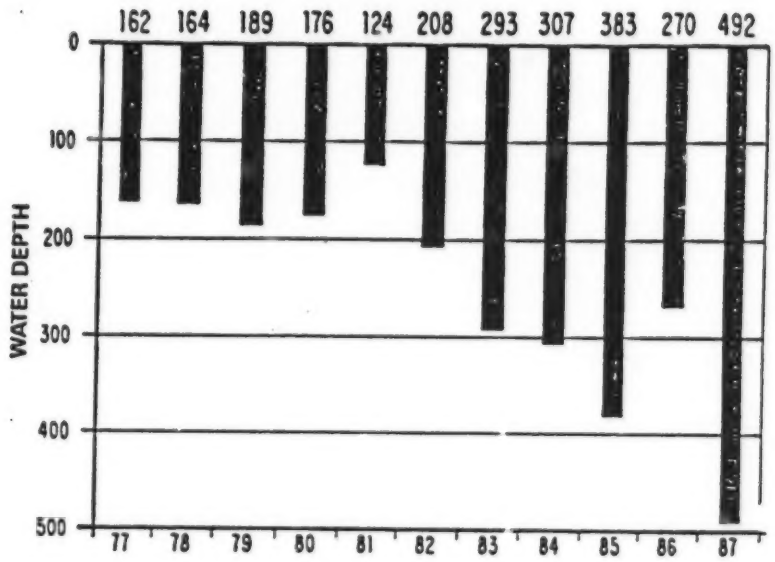

Figure 10: Subsea Completions —— water-depth evolution.

D. Consumption of petroleum products

The following remarks deal with the programs aimed at replacing petroleum products by alternative energy sources and raw materials.

(a) Proalcool

The "Alcohol's National Program" has been effective in replacing gasoline by ethanol, which is obtained in Brazil from sugar-cane. It has the advantage of being a domestic renewable source of energy.

Implemented in 1975, but only stimulated after the second international oil price shock, the "Proalcool" consisted of both adding anhydrous alcohol to gasoline, and using hydrous alcohol (fuel alcohol) directly as an automotive fuel.

Regarding the reduction of gasoline consumption, the program not only achieved its main objective (Figure 11), but also lead to a remarkable reduction in tetra-ethyl-lead consumption. However, owing to its unexpected acceleration, the program now requires redirectioning, as discussed later.

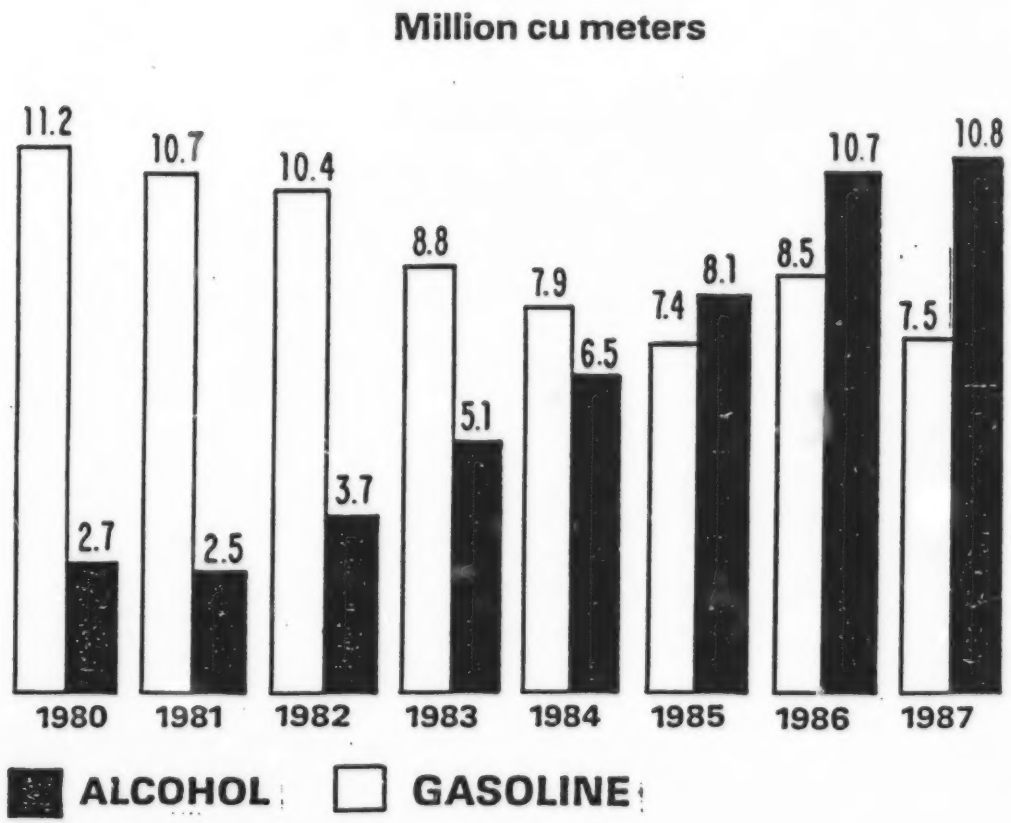

Figure 11: Fuel alcohol and gasoline consumption in Brazil.

(b) Fuel-oil

Fuel-oil has been the target of another replacement program. Mainly used in steel and cement factories, the replacement of fuel-oil by coal has considerably reduced its consumption.

Replacement of fuel-oil by biomasses has shown a slow progress, owing to (1) economic restrictions and to (2) the distance between prospective sources and consuming centers.

Recently, with the increasing supply of natural gas, fuel-oil replacement has gained another alternative. As a result of implementing such replacement programs, the importance of petroleum as a primary energy source has declined in Brazil, as shown in Figure 12.

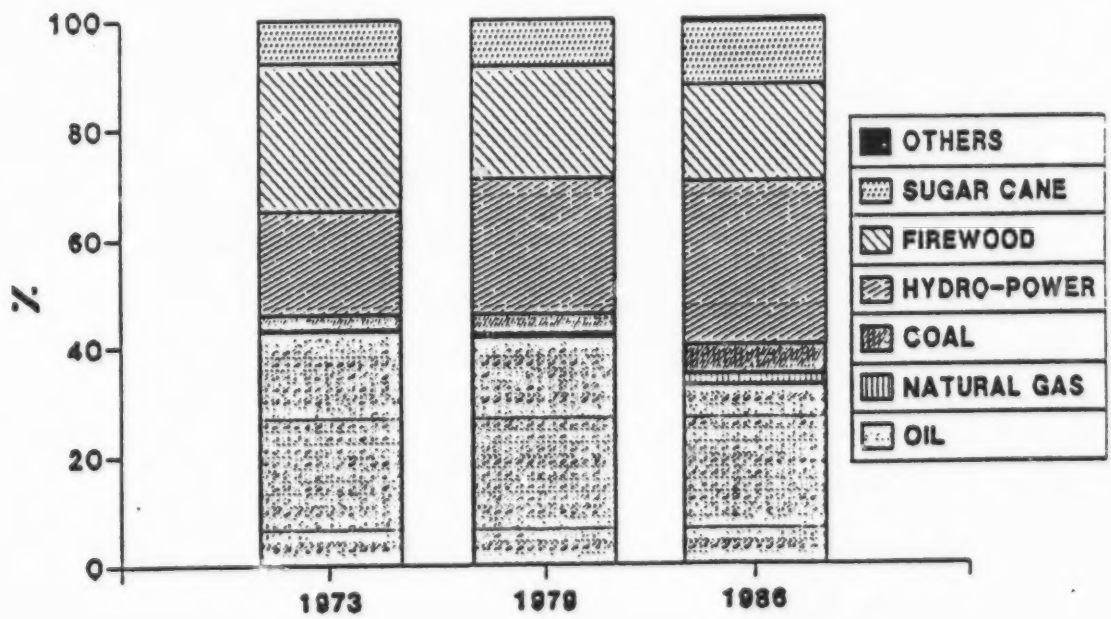

Figure 12: Energy consumption in Brazil.

Regarding petroleum products, the gasoline's share of demand decreased from 20.4% in 1979 to 13.4% in 1986, while the fuel-oil's share decreased from 28.9% to 17.9% in the same period (Figure 13). On the other hand, the diesel's share increased from 26.8% in 1979 to 34.5% in 1986, while the LPG's share increased from 7.0% to 11.0% in the same period.

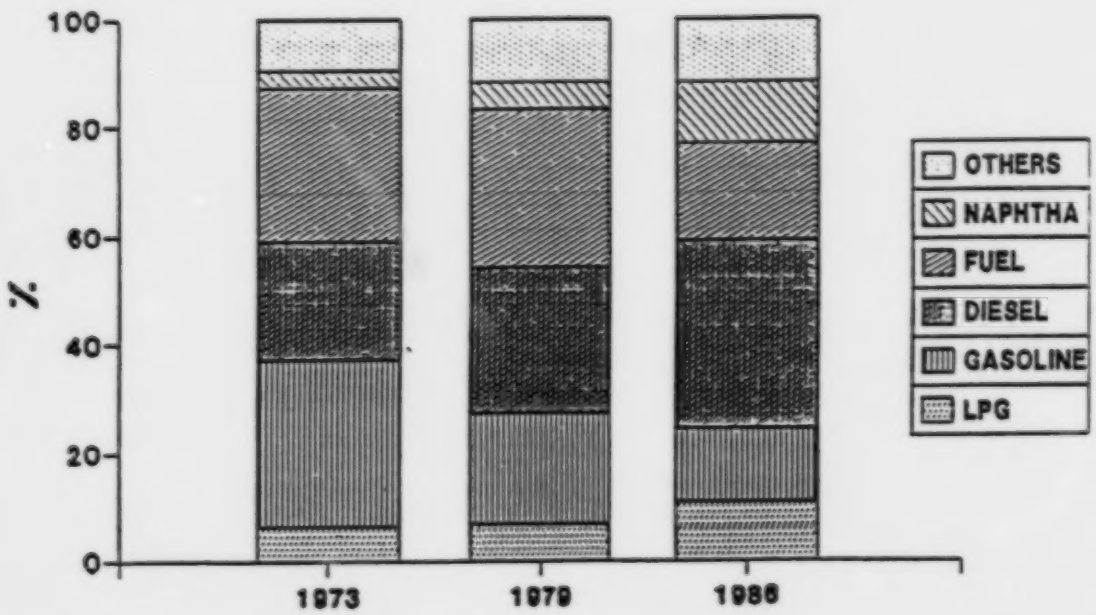

Figure 13: Petroleum products consumption structure.

While adapting itself to the changing domestic demand structure, Petrobrás not only has adjusted its refining complex, but also has taken additional measures to ensure petroleum products self-sufficiency. The "Botton-of-Barrel" program, for instance, was aimed at valorizing the refined products by (1) reducing the yield of heavy fractions, and by (2) increasing the yield of medium fractions.

Figure 14 illustrates the evolution of both the yield structure and the demand structure of oil products in Brazil from 1973 to 1987. Today's observed imbalance between yield and demand causes the Nation to consider the restatement of its energy policy. In 1979, when several energy plans were devised, the possibility of considerable increase in domestic oil and gas production was not properly assessed, and a progressive petroleum shortage in the international market was anticipated.

E. Perspectives

Brazilian dependence on imported petroleum, currently about 45% of consumption, should decrease in the near future, considering the excellent perspectives existing in the country (Figure 15). Assuming the oil production to reach 1,000,000 bopd in 1993 and 1,500,000 bopd in 1997, domestic oil prodution should meet 95% of consumption in ten years. This forecast is based (1) on an economic growth rate of 5% of the NGP, and (2) on an oil consumption increase rate of 3% per year.

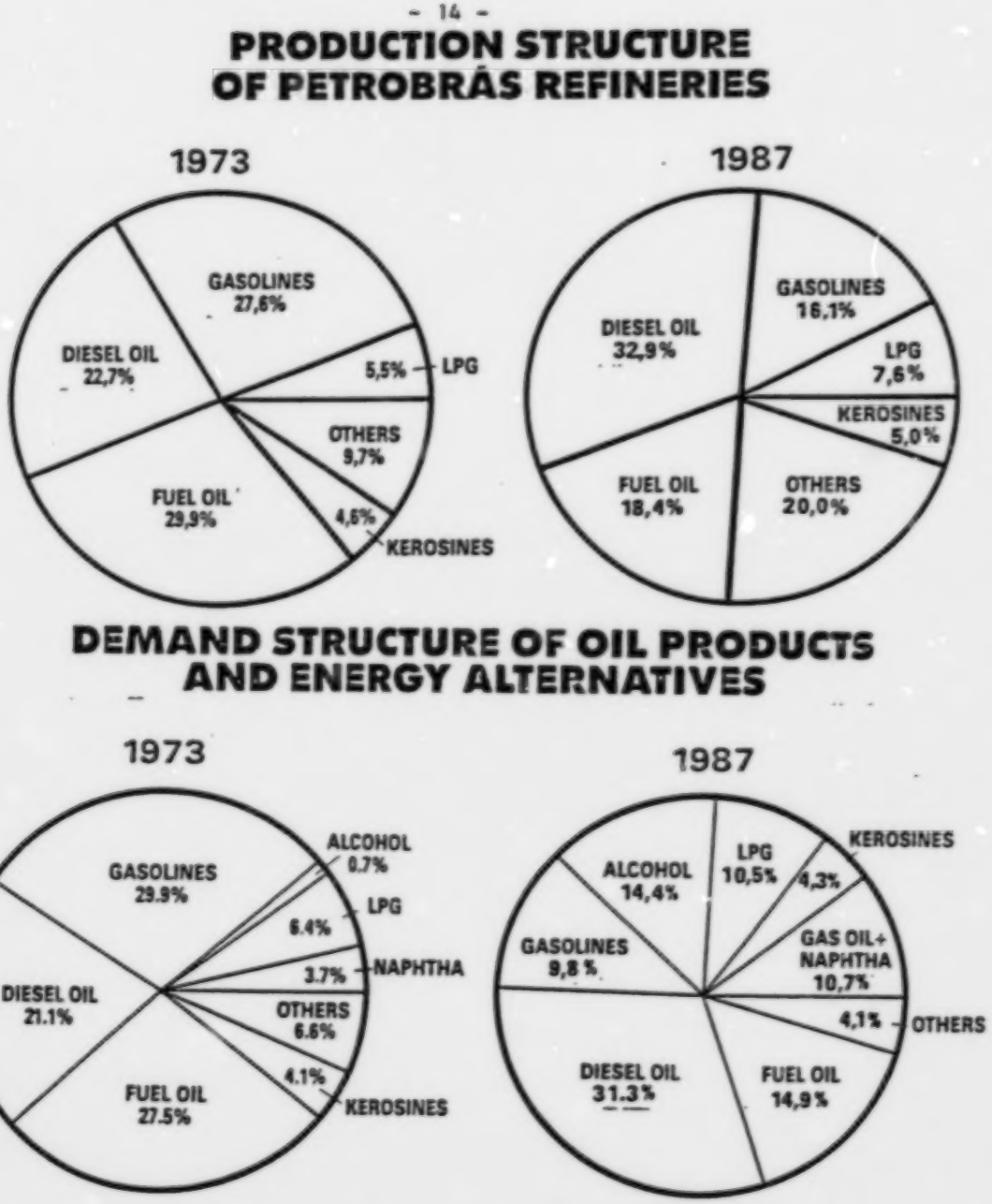

Figure 14: Evolution of both refinery yield structure and demand structure of petroleum products in Brazil between 1973 and 1987.

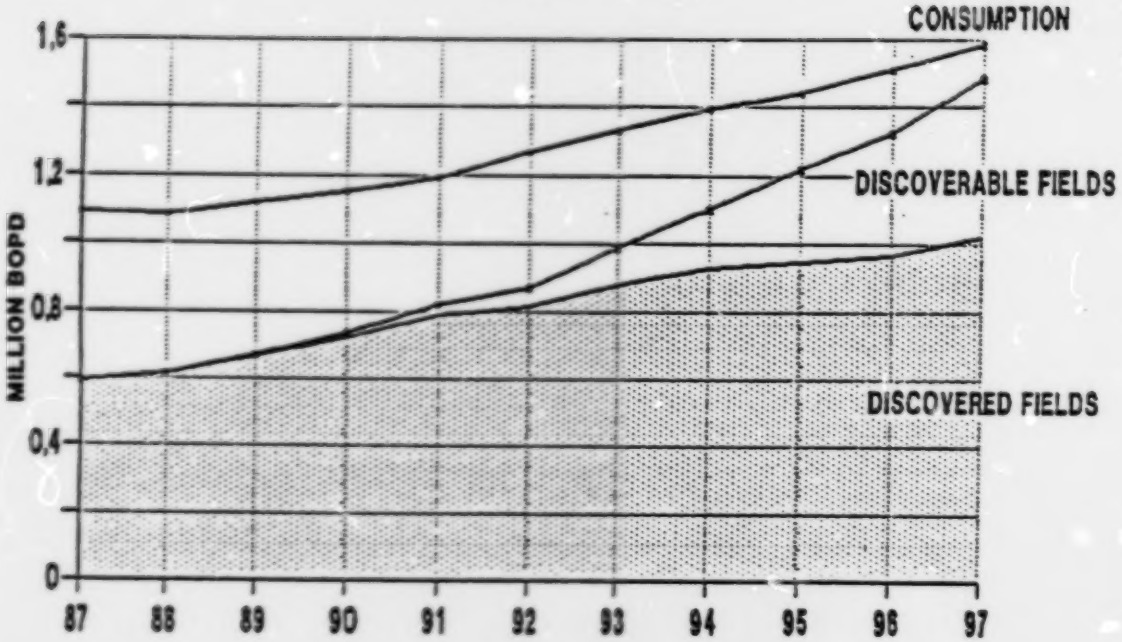

Figure 15: Forecasted crude oil production and consumption in Brazil.

ENERGY OPTIONS:
ENERGY AND CANADIANS INTO THE 21st CENTURY

by

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ENERGY OPTIONS:
ENERGY AND CANADIANS INTO
THE 21ST CENTURY

On April 13, 1987 the Honourable Marcel Masse, Minister of Energy, Mines and Resources Canada, announced Energy Options—A Canadian Dialogue. The process, to be undertaken at arms-length from the federal energy department, was orchestrated by a 24 person Advisory Committee under the chairmanship of Tom Kierens, President of Scotia Mcleod Inc. The Advisory Committee was in turn supported by a Secretariat, housed within the federal energy department but reporting directly to the Advisory Committee. The Secretariat, under the direction of Doug Patriquin, was charged with the responsibility for orchestrating the various conferences and special-topic seminars which constituted the formal component of the Energy Options process, and for commissioning, gathering, summarizing and forwarding the papers, submissions, technical reports and other forms of information and documentation which flowed to the Advisory Committee.

The Canadian Energy Research Institute became involved in Energy Options in February of 1987. The breadth of energy research expertise housed within the Institute provided a perfect match for this, the first comprehensive assessment of Canadian energy issues, policies and perspectives since the Borden Commission report of 1957. The CERI Board of Directors approved CERI's involvement in the process in March of 1987, and the Institute provided analytical, planning and information support to the Energy Options secretariat through to April of this year.

As the primary contact between CERI and the Energy Options Secretariat, my comments to you today are, admittedly, those of a supporter of this important dialogue on Canada's energy future. My remarks will be directed to the central conclusions and recommendations contained in the final report of the Advisory Committee to the Honourable Marcel Masse, entitled Energy and Canadians: Into the 21st Century, and to a

summary of what this report does and does not provide in terms of energy policy direction into the next century. Along the way, I will provide some editorial comments on the process and the conclusions reached; these are my personal observations, and should not be construed as the official position of CERI on the Energy Options dialogue.

First and foremost, it must be understood that Energy Options was not a "sources and resources" exercise. Information on Canada's energy economy was provided to the Advisory Committee and the hundreds of individuals who participated in this dialogue, but the intent of the exercise was not to plot an energy development strategy for Canada over the next 20-30 years or to in some way rank the various energy supply and demand initiatives available to energy producers, consumers and policy-makers.

Rather, Energy Options was a true dialogue among Canadians on what they perceived to be the role of energy and energy policy in Canada's future. The dialogue was open to all interested parties: energy producers, energy consumers, environmentalists, scientists, academics, and many others who shared a common interest in Canada's energy economy and energy future. In the eyes of many participants, the bringing together of the many disparate and often competing players in Canada's energy sector to focus on a common theme--Canada's energy future--was achievement enough to justify the expenditure for this far-reaching dialogue.

The Energy Options process also cut across the spectrum of energy sources and technologies, from conventional crude oil and natural gas development to solar energy and superconductivity. Indeed, the only groups not formally involved in the process were the various levels of government. There is little question that the decision by Minister Masse to have the public sector observe, rather than direct, the process contributed significantly to the outcome of this dialogue among Canadians.

Finally, there was very little that was taken as "given" in the dialogue. With the exception of an early concensus among pariticpants for a continuation of energy market deregulation as the cornerstone of future Canadian energy policy, all issues on Canada's energy agenda were open to challenge, from conventional resource development to the Free Trade Agreement between Canada and the United States and, on occasion, to the constitutional division of powers over energy ownership and development between the federal and provincial governments.

Given this mandate and agenda, perhaps the greatest accomplishment of the Energy Options process was the production of a report of any kind! This is a testimony to the diligence of the Energy Options secretariat and to the wisdom and patience of Tom Kierens and the members of the Advisory Committee.

Energy Options began with the concept of a Multiple Energy Future (slide 1). Over the past century, Canada has witnessed the ascendence, and subsequent decline, of first wood, then coal, and now crude oil as the primary source of energy used to power our industries and fuel our economy. As crude oil declines in relative importance as an energy source, numerous forms of energy--natural gas, electricity, coal and even a revival of renewable energy sources--are gaining importance in Canada's energy mix. It is likely that the next 20 years will not feature a dominant energy source in Canada's energy economy, but rather a large number of potential energy developments--including incremental supply through conservation and efficiency gains--competing for policy attention and development dollars. To the extent that government policy-makers remain involved in the energy market, they will have to carefully manage this multiple energy era in order to maximize the energy use and development options available to Canadians.

(Slide 2) In the broadest sense, Energy Options was the search for a set of principles, based on the opinions and suggestions of energy professionals and laymen, to guide future energy policy in the context of a noninterventionist market environment. The report of the Energy

Options Advisory Committee focussed on a seven-part policy framework, covering Energy and Development, Energy Security, Energy and the Environment, Energy Markets, Energy and the Fiscal System, Energy Efficiency, and Energy and Technology.

Energy and Development (Slide 3)

The participants in the Energy Options dialogue rejected the concept of hoarding Canada's energy resources in anticipation of greater returns to future development or as an energy legacy to future generations. A general belief in the ability of technological advancement to produce the necessary energy options as Canada's (and the worlds) supplies of conventional energies are depleted, lay behind the consensus for economic development of all of our energy potential, to benefit domestic industry and to generate export revenue.

Energy Security (Slide 4)

The issue of security of energy supply, which not long ago drove energy policy in Canada, was given only passing attention by participants. The security concerns, centered on the Territories and Atlantic Canada, were viewed as regional issues requiring national attention. However, the key message taken from the energy policy initiatives of the 1970s and early 1980s—that Canada cannot isolate herself from global energy developments--led to the vision of energy security as a search for increased options, rather than a call for hoarding of resources or development of uneconomic supply sources. Participants strongly rejected the use of security of energy supply as justification for acceleration of megaprojectes and other regional development initiatives.

Energy and the Environment (Slide 5)

Energy Options may well be remembered as the process which brought environmental concerns to the forefront of the energy agenda, and into the corporate boardrooms of energy producers and major energy consumers in Canada. The concept of environmentally sustainable development which, in its broadest form, states that economic development be

constrained by the ability of the ecosystem to absorb the accompanying pollutants, was widely adopted by participants. It is important to note that this does not mean a halt to energy development or use.

Before moving on, I would comment here that the cause of environmentalists in Canada has received a significant boost from the Energy Options process. **It is of critical importance that, having made their way into the corporate conscience in Canada, that the key players in this cause cease being lobbyists and make the transition to partners with industry in the pursuit of a common goal.**

Energy and Markets (Slide 6)

As mentioned earlier, participants strongly endorsed the current government position on deregulation of energy markets, and called for further initiatives into the electricity sector. Participants perceived the potential for future government intervention in the energy sector, for reasons of social or financial equity, but strongly recommended that such intervention not be pursued through distortion of market prices.

A number of troublesome conclusions were reached by the Advisory Committee in this area. First, it is debateable whether existing fiscal tools are capable of enhancing market mechanisms. In most cases, this is best accomplished by removing government intervention, rather than increasing it. Second, the concept of market-oriented regulation is at best a highly complex one, and at worst a contradiction in terms. Finally, the "full costing" of energy initiatives may defy definition in many cases, and be simply prohibitive in others. Policy-makers must tread carefully when examining these recommendations.

Energy and the Fiscal System (Slide 7)

The Energy Options process became mired in the concept of the "level playing field", a term which has strong connotations in peoples' minds but which appears to defy definition. The Advisory Committee

definition of non-discriminatory and neutral fiscal treatment of energy options comes close to what most participants were searching for. The key message in the area of fiscal systems is, however, the call for stability and predictability. The energy business, as all in this room will agree, is a high risk business. Instability in fiscal policy at the provincial and federal government levels adds an unnecessary and unwelcome element of uncertainty to the decision-making process; a poor but predictable fiscal policy environment is almost always preferred to the constant tinkering involved in the search for an elusive, optimal set of fiscal tools.

Energy Efficiency (Slide 8)

The demand side of the energy equation received a great deal of attention by participants. In particular, the statistically high level of energy intensity in the Canadian economy relative to her major trading partners became a focus of attention in the call for greater efficiency of energy use.

An item which is perhaps under-emphasized by the Advisory Committee in its report is the potential for energy savings remaining on the demand side of the energy equation. As an example, a strong case was made for energy conservation being the least expensive source of light crude oil--a barrel not consumed is a barrel of incremental supply. A key role for government in the future may be the research and development expenditures necessary to unlock this potential oil supply source.

Energy and Technology (Slide 9)

Technological advancement was viewed as the key to enhancing Canada's energy options and achieving the goal of environmentally sustainable development by the turn of the century. Participants ranked the funding of medium- to long-term research in technology development and transfer with information dessimination and monitoring of energy market development, as the most important roles for future government energy policy. In the long-run, it will be the ability of Canadian industry

to adopt new technologies, and to develop new processes tailored to Canadian needs and opportunities, which will determine Canada's future energy options.

In conclusion, it is useful to summarize what Energy Options has and has not provided current and future energy policy-makers (slide 10). Energy Options does not provide a long-term energy policy for Canada, nor does it provide an energy development strategy for the future. The report steers clear of specific prescriptions for energy resource development, other than to recommend project economics as the central guideline for development.

(Slide 11) Energy Options has provided a framework of principles for government energy policy within the context of a deregulated market environment. Important roles remain for energy policy, albiet further removed from the marketplace. In terms of the fiscal environment, participants called for a stable, predictable fiscal policy and a neutral, consistent position on resource development. Government boards and regulatory agencies, such as the NEB and ERCB, were seen as being more important in a deregulated market in providing information on market developments.

The environmental impact of energy use and development will become increasingly important over time. Participants favoured the "carrot" approach to environmental guidelines and standards, providing incentives for compliance as well as meaningful penalties for offenders.

Finally, a critical role for government policy will be the support of medium and long-term research, development and demonstration of energy technologies. A concerted effort to increase the level of government spending in the area of energy research will unlock the potential of Canada's energy economy, and allow us to pursue our energy options for the future well-being of all Canadians.

THE STATUS AND PERSPECTIVE OF ENERGY IN CHINA TO 2005

(ABSTRACT)

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At
The Seventh Annual CERI
International Oil and Gas Markets Conference
September 18-20, 1988
Convention Centre
Calgary, Alberta

THE STATUS AND PROSPECT OF ENERGY IN CHINA TO 2005

INTRODUCTION

Energy is an important material basis for developing social economy and improving people's living standard. Many countries have attached great importance to energy issues since the shock of two oil crises in 1970's. Although the contradiction between energy supply and demand has been alleviated in recent years, this is a temporary phenomenon after all. In the view of long term developing strategy, energy situation in future will still be severe.

In the course of modernization drive, how to solve energy issues will has all the time been concerned by the Chinese government. Since the foundation of the People's Republic of China energy industry has been developed greatly and significant achievments obtained. At present, both China's energy production and consumption rank the third in the world.Just because of great increase of energy production has China quaranteed the stable development of national economy. In order to speed up the construction of modernization, to develop energy industry greatly will be an important task for a long term in future.

1.ENERGY RESOURCES IN CHINA

By the end of 1986, China's total retained reserve of coal

had reached 845.8 billion tonnes. There is a complete range of coal varieties with bituminite, anthracite, coking coal, lignite and so on.

The theoretical reserve of hydropower resource in China reachs 680 GW with exploitable capacity 380 GW and annual electricity output 1900 TwH. ranking the first in the world.

Based upon the estimates of specialists at home and outside, the petroleum resources of China range from 60-50 billon tonnes.

China has rich resources of natural gas. Experts estimate that in depth of 3000 m, there are dozens of trillion cubic meters of natural gas waiting for us to explore and exploit.

2. ENERGY PRODUCTION AND CONSUMPTION IN CHINA

Since the foundation of People s Republic of china, energy production has been developed greatly and significant achievements has been obtained. In the period of 1949-1987, raw coal output increased from 32Mt to 928 Mt; crude oil, from 0.12 Mt to 134 Mt; natural gas, from 7M cubic meters to 13.87 billion cubic meters; and electricity generation from 4.3 TwH to 496 TWH. of which hydropower electricity generation ranged from 0.7 TWH to 99.5TWh. The total output of primary commercial energy (coal, oil, natural gas and hydropower) in 1987 was 912.65 Mtce, ranking the third in the world.

The energy output and primary energy structure in China

from 1949 to 1987 are shown in Table 1.

Table 1. TOTAL ENERGY OUTPUT FOR 1949 - 1987

year	Total energy output (Mtce)	Raw coal (Mt)	Crode oil (Mt)	Natural gas (Gm^3)	electricity generation (TWH) Total	Hydro
1949	23.71	32.0	0.12	0.007	4.3	0.7
1952	48.71	66.0	0.44	0.008	7.3	1.3
1957	98.61	131.0	1.46	0.07	19.3	4.6
1962	171.65	220.0	5.75	1.21	45.8	9.0
1965	188.24	232.0	11.31	1.10	67.6	10.4
1970	309.90	354.0	30.65	2.87	115.9	20.5
1975	487.54	482.0	77.06	6.85	195.8	47.6
1980	637.35	620.0	105.95	14.27	300.6	58.2
1985	855.46	872.0	124.90	12.93	410.7	92.4
1986	881.24	894.0	130.69	13.76	449.5	94.5
1987	912.65	926.0	134.00	13.87	496.0	99.5

Table 2 shows primary energy final consumption and structure, in which, the portion of energy for industry use occupies more than 60 %. It is one of the fundamental features of developing countries. In the recent years, in company with

Table 2. PRIMARY ENERGY FINAL CONSUMPTION AND ITS STRUCTURE

	1980		1985	
	Consumption (Mtce)	%	Consumption (Mtce)	%
Total final consumption	602.75	100.0	770.20	100.0
1.Material production sectors	480.55	79.7	586.45	76.1
A. Agricuture	46.92	7.8	56.11	7.3
B. Industry	389.86	64.7	471.73	61.2
a.Heavy industry	322.14	53.4	376.83	48.9
b.Light industry	67.72	11.2	94.90	12.3
C. Building construction	9.57	1.6	13.01	1.7
D. Transpotion and posts tele-communication	29.02	4.8	37.15	4.8
E. Commercial sector	5.18	0.9	8.45	1.1
2. Non-material production Sector	12.05	2.0	15.94	2.1
3. Residencial consumption	110.15	18.3	167.81	21.8

the development of national economy and the improvement of people's living standards. the portion of industry energy consumption decreases, and that of residential consumption increase year by year. This trend will continue hereafter.

3. ENERGY DEMAND AND SUPPLY FORECASTS IN CHINA TO 2005

In recent years.the domestic and oversea experts have forecasted energy demand of China in 2000. All forecasts are based on achieving the strategic target of quadrupling its total industrial and agricultural production output from 1980 to

2000. Meanwhile, the change of economic structure, increasing of living standard, technology progress and measures of energy conservation, resource condition and policies of government and etc. factors are considered. Main results of forecast are showed in Table 3.

From Table 3., it is noted that the results forecast is nearing, because the assumptive conditions and forecast methods are identical basically. It must be pointed out that the total primary energy demand of 1400-1500 Mtce which is a minimum in 2000. Considered that the practic speed of economic development in recent years is higher than original goal, the total primary energy demand in 2000 may be over the above figures.

The main factors of influencing the energy supply are energy investment, technical level of energy development and utilization, transportation and environment, resources of water along with energy policies of government and so on.

According to the aforementioned factors, experts estimated that the total primary energy production of China in 2000 will be 1230 - 1430 Mtce this is shown in Table 4. Now it seems that the price of oil goes down in the international market, and will impact the speed of oil industry development. High speed development of oil and natural gas industries will meet difficulties. The development speed of nuclear power will depend on capital investment. We cannot be optimistic. The difference between supply and demand is made up only by coal.

Table 3. FORECASTS OF CHINA ENERGY DEMAND IN 2000

Forecast Institutions	Forecast Methods and Time	Total demand (Mtce)	Structure (%)				
			Coal	Oil	Natural gas	Hydropower	Nuclear power
1. Energy Research Institute of State Planning commission	Sector Integrated 1984	1469	66.87	23.36	3.17		6.60
2. Nuclear Energy Institute of Qing Hua University*	Dynamic Input-output model 1985	1455	67.42	20.17	4.57	6.67	1.17
3. The World Bank	Sector Integrated analysis 1984	1428	78.71	14.01	0.91		6.37

* Premise that gross industry and agriculture output value in 2000 will be 4.6 times as much as that in 1980.

** The forecast of the ERI include the demand of energy export, the others only include domestic demand.

Table 4. FORECAST OF CHINA ENERGY SUPPLY IN 2000

	Material object			Htce		Structure %	
	Unit	Low plan	High plan	Low plan	High plan	Low plan	High plan
Raw coal	Mt	1200	1400	875	1000	69.8	69.8
Crud oil	Mt	180	200	257	286	20.9	20.0
Natural gas	Gm	25	35	33	47	2.7	3.3
Hydro power	Twh	200	250	72	90	5.9	6.3
Nuclear power	Twh	25	25	9	9	0.7	0.6
Total				1226	1432	100.0	100.0

Note: Coal consumption of per KWH power calculated according to 360 GCE.

The forecast results of supply and demand make it clear that the primary energy demand of China in 2000 will may have a considerable gap. The contradiction between supply and demand of electric power, oil, and other high quality energy will be particularly outstanding. Experts estimate that the demand of electric power in 2000 is 1.2 PWH and crud oil is 250 - 260 Mt. In fact, supply falls short of demand. At that time, China will probably change into an import oil country from an export oil country. So, the government must speed up the energy industry development which has the centre of electric power.

One important conditions of the aforesaid forecast is that the energy consumption per unit output value will suddenly be droped. On the one hand the specific energy consumption of main industrial products in the end of this century will reach international advanced level of the end of 70's and the early of 80's. On the other hand, the industrial structure and the product structure will rationally be adjusted. Therefore the specific energy consumption will go down by wide range and the indirect potential of energy conservation will fully be exploited.

The forecast of energy demand in 2005 goes on under the following assumed conditions:

1. The gross output value of industrial and

agricuture will quadruple from 1980 to 2000. The total energy consumption and energy structure can be found from Table 6's figure that made by Energy Research Institute.

2. The gross output value of industrial and agriculture will be double from 2000 to 2015 and will increase one third each 5 years.

3. Energy elastic factor is 0.7.

According to assumotions stated above, the forecast result in 2005 is that total energy consumption is 181 Mtce and energy structure is that coal is 67 %, oil 19.8 %, natural gas 5.2 %, hydropower 7 %, nuclear power 1 %. And the material object is: raw coal 1700 Mt, crud oil 250 Mt, natrural gas 70 Gm^3, hydropower 350 Twh, nuclear power 50 Twh.

4.EXPLORATION AND DEVELOPMENT IN CHINA'S OFFSHORE OIL SECTOR

China embarked on Sino-foreign cooperation in the offshore oil sector in 1979. By the end of 1987, the China National Offshore Oil Corporation (CNOOC) had signed 39 petroleum contracts and geophysical survey agreements with 45 companies from 12 countries, through bi-lateral negotiations and two bidding rounds, and a total of 179 exploratory wells (including CNOOC financed) had been drilled, resulting in 77 oil and gas discoveries and the definition of 39 petroliferous structures.

With respect to field development, two fields are already on stream, the Chengbei field under Sino-Japanese cooperation in the Behai gulf and Weizhou 10-3 field under

Sino - French cooperation in the Beibu Gulf in the South China Sea, both producing above 400 thousand tonnes crude oil per year. In addition, development of BZ 28-1 and other 6 fields are now under way, giving an expectation of annual oil production of three million tonnes from china offshore in 1990.

Over the past 9 years, we have furthered our understanding of the occurence, accumulation and migration of hydrocarbon resources on Chinese continental shelf. A success rate of 30 % in the offshore exploratory drilling has been made, which should not be regarded as a low figure.We have faith in promising prospects for China's offshore oil, with the extensive continental shelf and less than one third of the propective structures having been tested.

This year we have witnessed more encouraging oil and gas discoveres, among which Huizhou 26-1-1 well, located in the east of Pearl River Mouth of the South China Sea, is the best. The well was tested at 42 hundred cubic meters per day crude oil,the highest oil production both of tested well on China's offshore, and of a production well in a sandstone layer by far in China, showing the great potential for new breakthroughs in prospecting on the Pearl River Mouth Basin.

The second round bidding met the oil price collapse which forced oil companies to cut back extensively exploratory and developing expenditures. So, we have taken some flexible policies and approaches.

Recently, CNNOC will carry out the third round bidding.

They will make adjustments to the exploration clauses and fiscal terms in the model contract based on the principle of reducing the investment risks shouldered by foreign companies, providing foreign operators with more latitude and ensuring reasonable profits of foreign contrctors. We believe that more foreign oil companies will explore and develop china offshore oil with us.

UNITED STATES OIL AND GAS POLICY
IN A BROAD NATIONAL AND INTERNATIONAL CONTEXT

Presented by

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Good afternoon. It is indeed a pleasure to be here today to participate in the 7th CERI International Oil and Gas Markets Conference. This is my first trip to Calgary, and I hope it won't be my last. Thank you for your invitation.

Our time frame today is through the year 2005. I wonder if at the 24th Annual CERI Meeting in the year 2005—if my calculations are correct—this panel will be asked to defend, or take credit for, our statements here today. Given that possibility and the Department of Energy's track record on projections, I will not be making any predictions today but rather will concentrate on describing the new environment we all face and how it affects oil and gas prospects.

Joan Robinson, a British economist, noted "In order to know anything, you must know everything" . This is true for economics and it's certainly true for energy. She went on to say "But in order to talk about anything, it is necessary to leave out a great deal" . As last speaker, I must deliberately neglect a great deal—much of which has already been covered by other speakers. But what cannot be neglected is my central theme—energy cannot be viewed in isolation. It is part and parcel of a nation's economic, social and political environment.

In the 1970s, conventional wisdom focused on simple, singular and isolated solutions to the energy crisis. The United States and some other countries embarked on a panic response to

deal with the 1973 and 1979 oil shocks. The twin shocks cost the western industrialized nations $1.2 trillion. Inflation in the U.S. tripled and unemployment doubled. Many countries developed crash programs and most of the time, they did just that—they crashed. For example, we, in the U.S., created Project Independence, believing we could insulate ourselves from world events. Experience has taught us just how inter-related the energy market is. We must coordinate our policies with those of our allies to be effective.

The 1970s can be characterized by shortages, price shocks, and gas lines. In the 1980s, we have an oil surplus, lower prices and economic growth. However, the 1990s will be different. Trends show we must being planning now if we are to avoid energy supply problems and the energy debate must take place on a global scale.

What I would suggest to you is that our national well-being depends on many related factors (see chart 1), including:

- Economic Growth
- National Defense
- Trade Deficits
- Energy Prices
- Federal Budget Deficit
- Environment - a major challenge in the 1990s.

The linkages are complex, and the Nation's focus on the issues changes frequently. In addition, some of these factors are important to various interest groups, which at times have mustered considerable organizational and persuasive skills to influence the nation and Congress to take some action, or at least focus on the problems associated with this factor for a while.

If a concern can be easily solved with a short-term answer, Congress often can act quickly to provide some remedy (for example, the drought relief to farmers this summer). However, when the issues are complex and require long-term solutions, it becomes more difficult to reach a consensus. In particular, complex linkages between different and often competing national concerns can hinder a response to a problem.

It is often the case that energy security concerns appear to conflict with other national concerns. For example, low oil prices have been a boon for consumers but have wreaked havoc on our domestic oil industry. In the long-term a weakened domestic oil industry is detrimental to

U.S. energy security. In other instances a solution to one problem can be undone by the solution to another. Sometimes such conflicts are real and cannot be ignored. In other cases, there may be a conflict in the short-term but not in the long-term (or vice versa). In still other cases, there may be common ground between energy and one or more other important national concerns.

Of course we are more likely to achieve a policy consensus if we can identify actions that address both our energy concerns and our other priorities. Over the longer term, these interests tend to converge. For example, we would be hard-pressed to have a healthy economy and a strong national defense in the future if we were to ignore our energy security concerns today.

To set the scene, I would like to briefly set forth the outlook for oil in the 1990s.

Since the price collapse of 1986 the United States has lost about 1 million barrels a day of oil production. Currently net imports represent 36 percent of our oil consumption. (See chart 2) However, the trends are not good. With continued low oil prices import levels are on the rise. Net imports have grown almost 10 percent since 1985.

If oil prices remain low, the United States is likely to import more than half of its oil by 1990. Our oil imports could reach 60% of consumption by 1995. (See chart 3) We see similar trends elsewhere in other OECD countries. Their imports could rise from 64% today to 75% by the mid-1990s. And we foresee an increasing share of the world's oil demand in the rapidly industrializing nations. While there is nothing wrong with oil imports per se, the problem is where we get that oil.

Since two-thirds of the world's excess productive capacity and oil reserves lie in the Persian Gulf, the West will become increasingly dependent on producers there—possibly even more than in the 1970s. In fact, we estimate that about half of the world's oil will come from the Persian Gulf by 1995.

We know that we have a serious collective energy security challenge. We know that the problem is not just oil-related. The use of any non-oil energy resource, such as natural gas, nuclear, alternative fuels, renewable energy sources, can reduce oil dependence. We know that no one country can solve the problem because it's really the collective demand on the Persian Gulf which threatens our mutual security. And we also know that energy policies must be complementary to economic policies and to national security concerns.

Given that setting, it is useful to take a look at some energy policy issues we are facing today and examine how they affect our prospects for the longer term. In doing so, it is important to keep in mind that these options have not only direct effects on energy production and consumption but on the whole economy as well. Government policies can have complex second and third order effects which are difficult to anticipate.

Strategic Petroleum Reserve is our number one defense against supply disruptions

The government began purchasing oil for the Strategic Petroleum Reserve (SPR) in 1977. The Reserve is an essential part of the U.S.emergency preparedness and represents an $18 billion investment. The SPR has grown fivefold to more than 550 million barrels since 1980. This amount is equivalent to 3 months of current U.S. imports, and since no conceivable supply disruption could cut off all sources of U.S. imports, the effective coverage in a disruption would be considerably larger. In addition, the very existence of the SPR reduces the possibility of a politically motivated embargo by minimizing most of the economic turmoil which followed the previous oil shocks. However, as we enter the 1990s the challenge is to continue to fill the Reserve during a period of budget constraints. (See chart 4)

Arctic National Wildlife Refuge Coastal Plain has a potentially large energy and economic payoff for the entire country.

From an energy standpoint, the Arctic National Wildlife Refuge Coastal Plain (ANWR) has been described as the best domestic oil prospect known today. It is located just 65 miles to the east of the Nation's largest oil field, Prudhoe Bay, on Alaska's North Slope. Over the past 10 years, about one-half of Prudhoe Bay's 10 billion barrels of oil reserves has been produced, and production is expected to decline soon form the current peak of about 1.6 MMBD. (See chart 5) Today, Prudhoe Bay represents 20 percent of U.S. crude production, but this level will be much smaller by the year 2000, while imports are expected to rise.

A thorough geological survey indicates that the ANWR Coastal Plain could contain as much as 9.2 billion barrels of economically recoverable oil reserves—a potential 34 percent increase over current U.S. oil reserves of 27 billion barrels. If ANWR oil reserves approach the size of Prudhoe Bay, production from the Coastal Plain could be as much as 1.5 million barrels per day. Furthermore, ANWR production would be readily accessible to the Trans-Alaska Pipeline System.

In spite of the large potential resources of the ANWR Coastal Plain and the oil industry's capabilities for limiting the environmental effects of developing those resources, many question whether the nation really needs the oil that may be present in ANWR. They suggest that the U.S. can meet its energy needs through greater energy conservation alone. It is my belief while conservation will certainly help it will not be enough.

Among the targets for additional conservation in the United States are increased efficiency in home heating (through more insulation and improved furnaces), and in appliances. Such additional conservation will have little impact on U.S. oil use, however, because home heating and electricity generation account for only 7 percent of our oil consumption. Nearly two-thirds of all our total oil consumption is used in the transportation sector. (See chart 6) Thus, the main target for reducing U.S. oil must must be in this area.

There are sound economic reasons to explore and develop our best domestic oil prospects. If large recoverable resources are found in ANWR, there will be substantial economic benefits for all Americans—an estimated $80 billion or more. First, the State of Alaska and the Federal Government would collect increased revenues through large tax and royalty payments from the oil companies. Secondly, businesses throughout the United States would benefit directly or indirectly from expanded business opportunities arising from the oil industry's purchases of a variety of goods and services. Finally, all Americans would profit from reduced national expenditures for imported oil and reduced vulnerability to future oil supply disruptions. (See chart 7)

Oil and natural gas policy options must be considered in their broader economic and national contexts

Several quick-fix measures have been suggested to limit oil imports, but each has significant drawbacks when analyzed in its broader national and international context. Some of these proposals include:

A Gasoline Tax: A gasoline tax discourages consumption, does nothing for production, but is a better revenue raiser than import fee. However, its ramifications adversely effect other parts of the economy. (See chart 8) It is a regressive tax and disproportionally hits some parts of the economy such as the trucking industry, farmers, and low-income citizens.

An Oil Import Fee: The U.S. has the highest oil production costs of any country in the world. (See chart 9) An oil import fee would strengthen energy security—helping to even out this cost differential—but would cause large economic dislocations. A $10 per barrel fee could generate $46 billion in revenues but would simultaneously cause a reduction in economic growth rate costing four times that amount and eliminate three times as many jobs as would be created in the oil industry and related service areas. (See chart 8)

In addition, implementation of the fee would be problematic. It raises all kinds of questions. For example, under the recently signed U.S.-Canada Free Trade Agreement Canada would be exempted. We would probably want to do so for other countries. Would you exempt home heating oil and farmers from the fee? The more exemptions one allows, the less effective the fee becomes.

Oil and Gas Tax Incentives: The U.S. is a mature oil province. Much of our crude production comes from low-output wells. (See chart 10) Oil and gas tax incentives would help us on energy security by stimulating domestic production, but would cost us government revenues. But we must weigh the long-term cost of losing production forever, thereby increasing our dependence on imported oil, against the cost of lost Federal revenues. (See chart 11) Also timing is a problem considering the tax reform we have just undergone. The issue is further complicated by public perception that such measures are giving tax breaks to big business. (See chart 12)

Some of the proposed incentives include:

- Repealing the Transfer Rule: The current transfer rule prohibits the use of percentage depletion on oil properties transferred from one company to another. With their comparatively high overhead costs, large, integrated oil companies often find it uneconomic to continue operating low-output wells. This rule, however, discourages the transfer of such wells to independent oil companies, because it does not allow independent producers to use the percentage depletion allowance on wells purchased from other companies. If the wells are not transferred, the large, integrated producer may choose to shut down the well altogether. The repeal of the transfer rule would help keep such wells in operation and to prevent abandonment of recoverable oil reserves.

- Increasing the Net Income Limitation: The net income limitation limits percentage depletion deductions to 50 percent of a company's net income. Thus, a high-cost producer with

a low net income is not allowed to deduct as much percentage depletion as a more profitable producer. This limitation, therefore, can reduce the incentives for continued operation of high-cost, low-output wells. The President proposed increasing the net income limitation to 100 percent, so that high costs and low oil prices would not be as great a disincentive to continued operation of low-volume wells.

- Expensing G&G costs: Allowing faster recovery of geological and geophysical (G&G) costs by permitting companies to expense, rather than capitalize, G&G costs for federal income tax purposes. This would act as an incentive for geological mapping, gathering seismic data, and other work that precedes exploratory drilling and thereby encourage exploration and development for oil and gas.

- Establishing an Exploration and Development tax credit: An exploration and development tax credit for a fixed percentage of some or all exploration and development expenses would reduce the after-tax costs of finding and producing oil and lead to higher domestic production.

- Increasing or Expanding Depletion Allowance: Increasing the depletion allowance, for example, from 15 to 27.5 percent for all independent producers. Or alternatively, the percentage depletion allowance could be made available to major oil companies for new production. These proposals would increase the profitability of oil and gas activity and would encourage domestic production.

- Permitting R&D Tax Credits for Enhanced Oil Recovery Research: Qualifying enhanced oil recovery (EOR) projects for the existing research and development tax credit. Enhanced oil recovery projects are in a sense experimental projects and thus could qualify for the R&D tax credit available to all U.S. industries. This would encourage EOR technology development and commercialization.

The National Context—The Political Realities and Our Decision Making Process

This is just a sample of the very complex challenges which face us today. No longer are platitudes, slogans and rhetoric going to carry the day. What we need today is strong analytical work to ensure that decisions are consistent with economics and national security. When issues of competing national interests arise, they often become characterized as producer vs. consumer issues. It isn't that simple.

First of all, we produce energy in a variety of ways in the United States, so *producers* are rarely united, particularly among competing fuels and sometimes for a particular fuel.

Secondly, so-called producer/consumer issues often manifest themselves as regional issues. The U.S. consumes more than it produces overall, but important regions are very dependent on energy production for their economic well being.

Finally, what is good for the producer in the short-term may be good for the consumer in the long-term (and vice versa), so it is not always clear whether a policy is pro-consumer or pro-producer. Ultimately, our energy concerns focus on the long-term interests of consumers, but the continued viability of domestic producers is vital to those long-term consumer interests.

We, at the Department of Energy, try to sort out the overall effects of existing and potential energy policies using a variety of tools, ranging from back of the envelope calculations to sophisticated econometric and operations research models. In the end, however, it generally is the political process, aided we hope by the fruits of our labor, that sorts out the priorities and sets our policy. Indeed the political process is the only way I see for achieving balance between various regional and economic interests affected by our government policies.

The International Context must be considered in the energy policy decision making process

Even when we can sort out the various national interests, we often are faced with the fact that many energy concerns are international in scope. Fore example, acid rain and the greenhouse effect are concerns which cross national borders; oil supply disruptions in an integrated world market affect all consuming countries, regardless of their import sources; energy trade is by its nature of international concern.

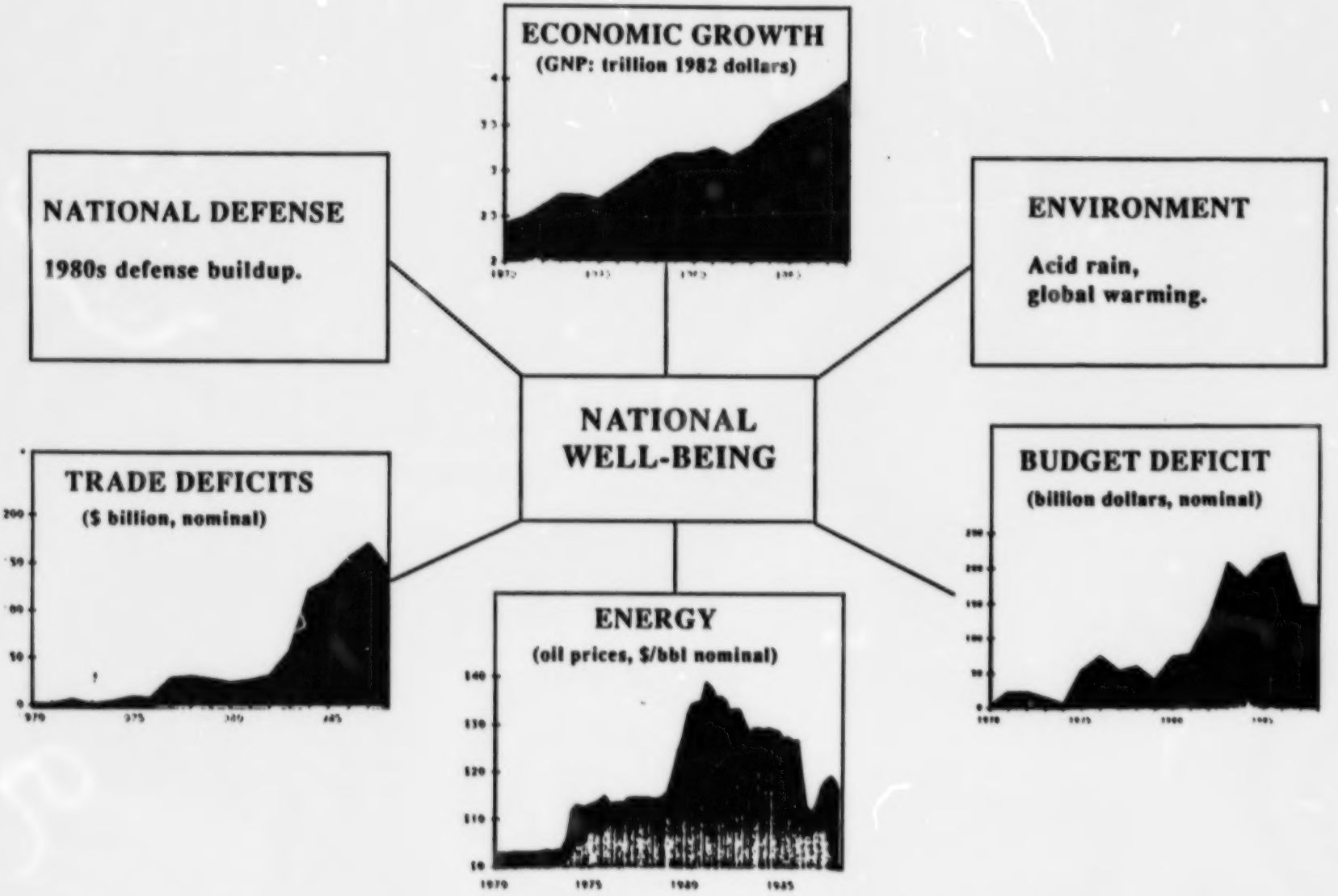
I mentioned that priorities change frequently, and I would like to introduce the concept of a *national concern index* to explore this issue. (See chart 13) I'm not sure how you could really calculate an index of the public's concern over various issues—perhaps by counting newspaper articles, studying polling data, or examining the positions of winning and losing politicians. So I have drawn these curves to show basic trends: public concern about energy security increases with oil price hikes (and vice versa); environmental concern rose in the 1970s, declined briefly, and is on the rise again; and there has been an increase in public concern about government spending as Federal deficits have risen. The economy and national security are always preeminent concerns, so I have not included them on this chart. I would point out that while this

chart illustrates approximate trends in public concern, it does not purport to show the relative importance of various problems.

Boom bust cycles in energy tend to lead to alternating periods of panic and complacency. With shortages and high prices in the 1970s, energy outweighed many other concerns, and the government took strong actions. Unfortunately many of these actions were counterproductive. With low oil and gas prices and plentiful supplies today, public perception has placed energy security on the back burner. But energy very well could emerge as a major national concern in the 1990s.

To conclude, those of us leading the charge on energy policy must deal with the problems of a short-term mentality, regional divisions, and producer/consumer and producer/producer conflicts. Our analyses can contribute to the policy making process by helping to better define the issues and by providing information about energy markets, both current and expected future, and about the impacts that various government policies can have on energy markets and on the economy. Ultimately the political process, on behalf of the voting public, will decide the larger energy policy issues. But we need to begin planning now to avoid being caught short as we were in the 1970s. (See chart 14)

NATIONAL WELL-BEING DEPENDS ON MANY RELATED FACTORS

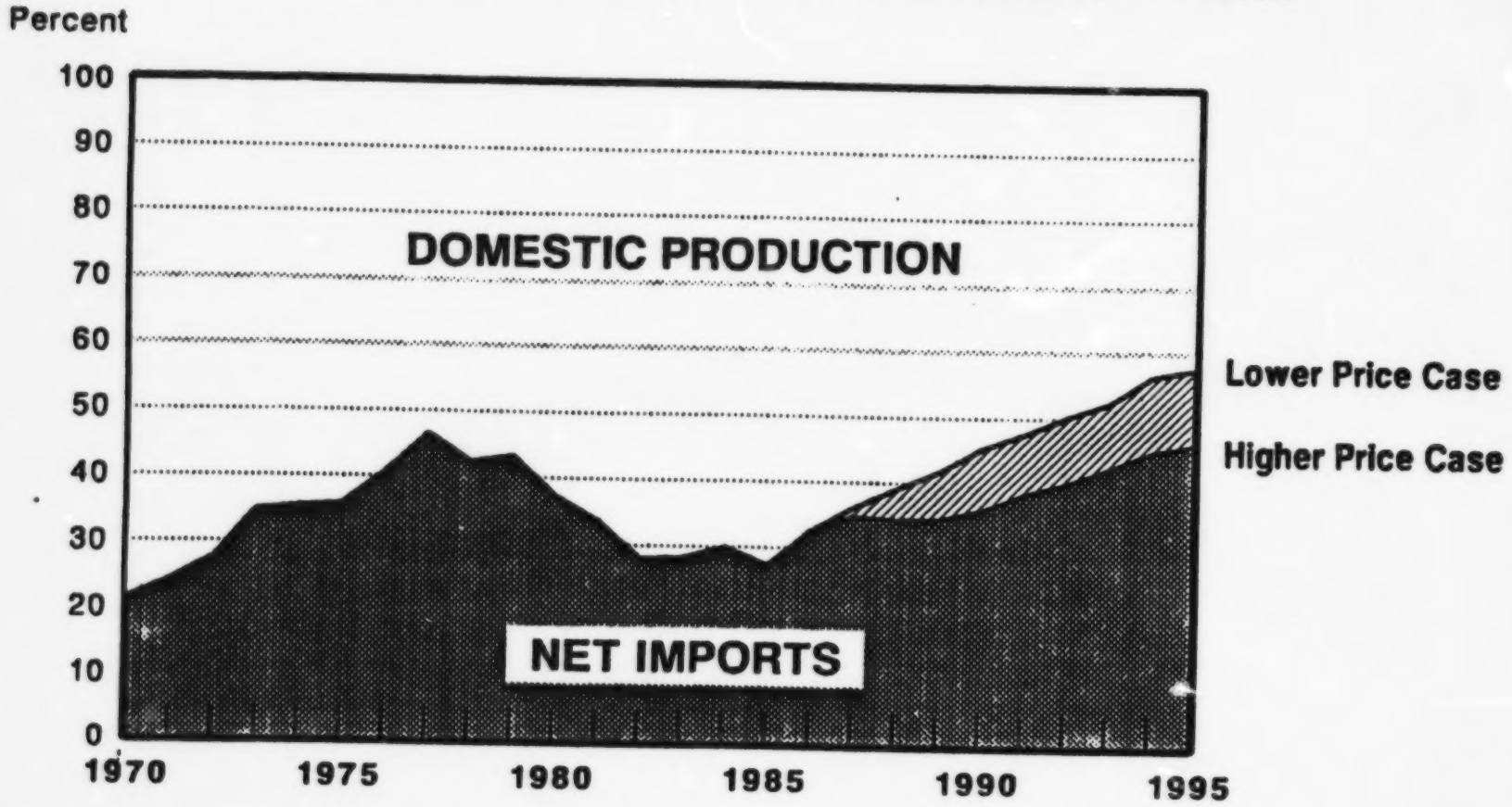


SOURCES OF U.S. OIL SUPPLY

(In Millions of Barrels per Day)

TOTAL	**16.67**
DOMESTIC CRUDE PRODUCTION	8.35
OTHER DOMESTIC	1.60
IMPORTS	
CANADA	.85
VENEZUELA	.75
SAUDI ARABIA	.75
MEXICO	.65
NIGERIA	.55
UNITED KINGDOM	.35
ALGERIA	.30
INDONESIA	.30
OTHER OPEC	.40
OTHER NON-OPEC	1.70

UNITED STATES NET OIL IMPORTS AS PERCENTAGE OF CONSUMPTION



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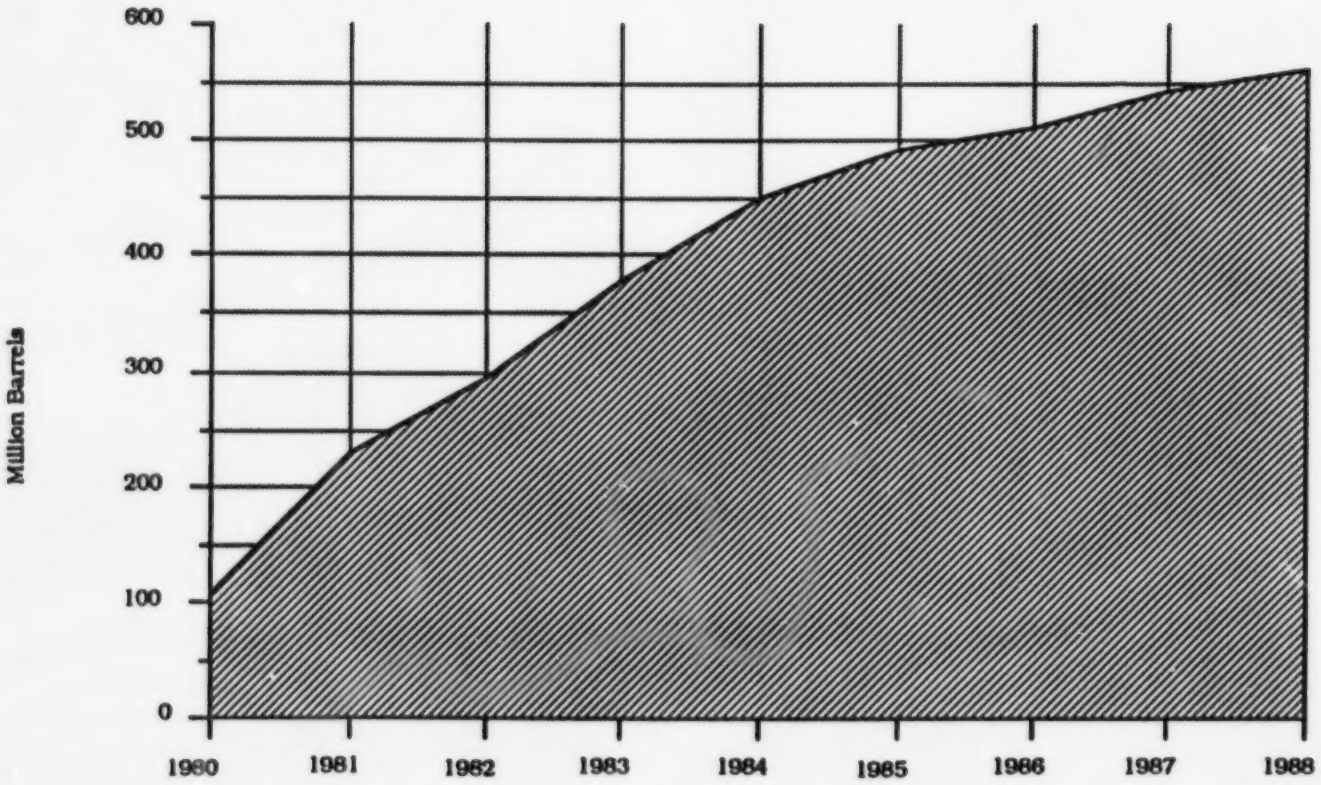
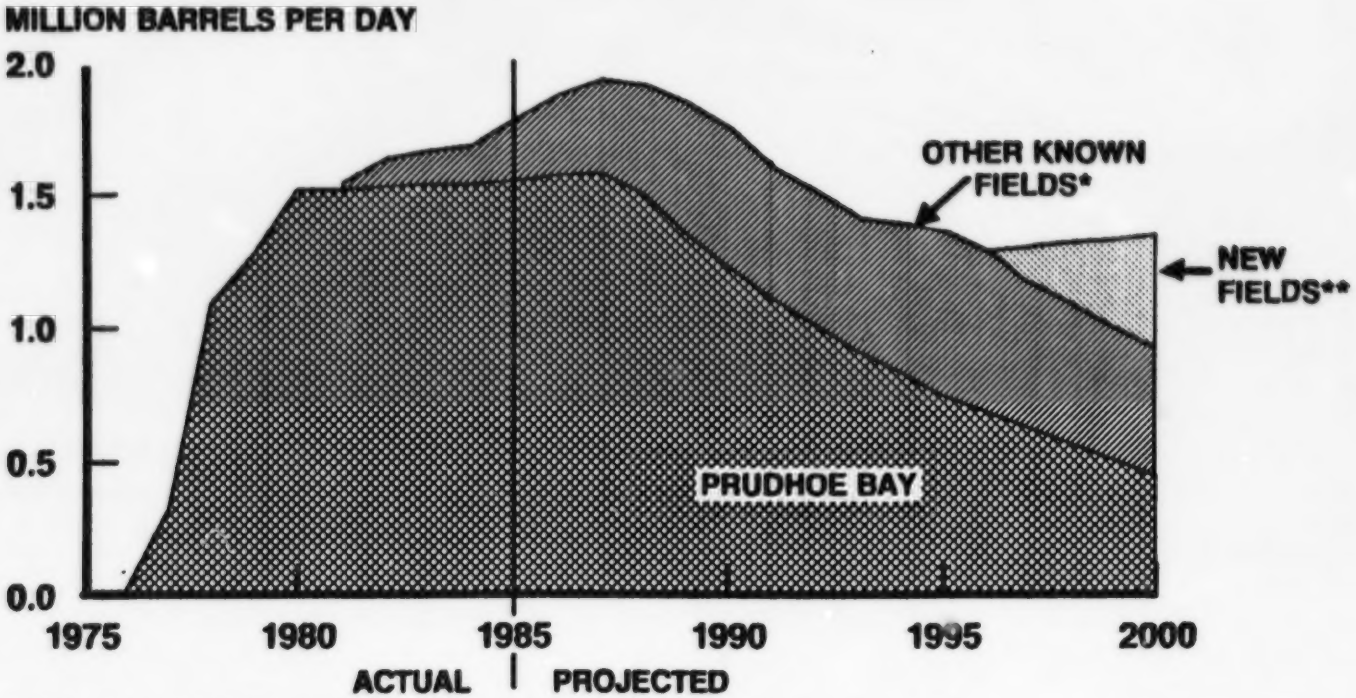
U. S. Strategic Petroleum Reserve



ALASKAN NORTH SLOPE OIL PRODUCTION



*INCLUDES KUPARUK, LISBURNE, MILNE POINT, NGL PROJECT, GWYDYR BAY, POINT THOMPSON, SEAL ISLAND, AND WEST SAK

**INCLUDES POTENTIAL DEVELOPMENT OF THE ARCTIC NATIONAL WILDLIFE REFUGE (ANWR)

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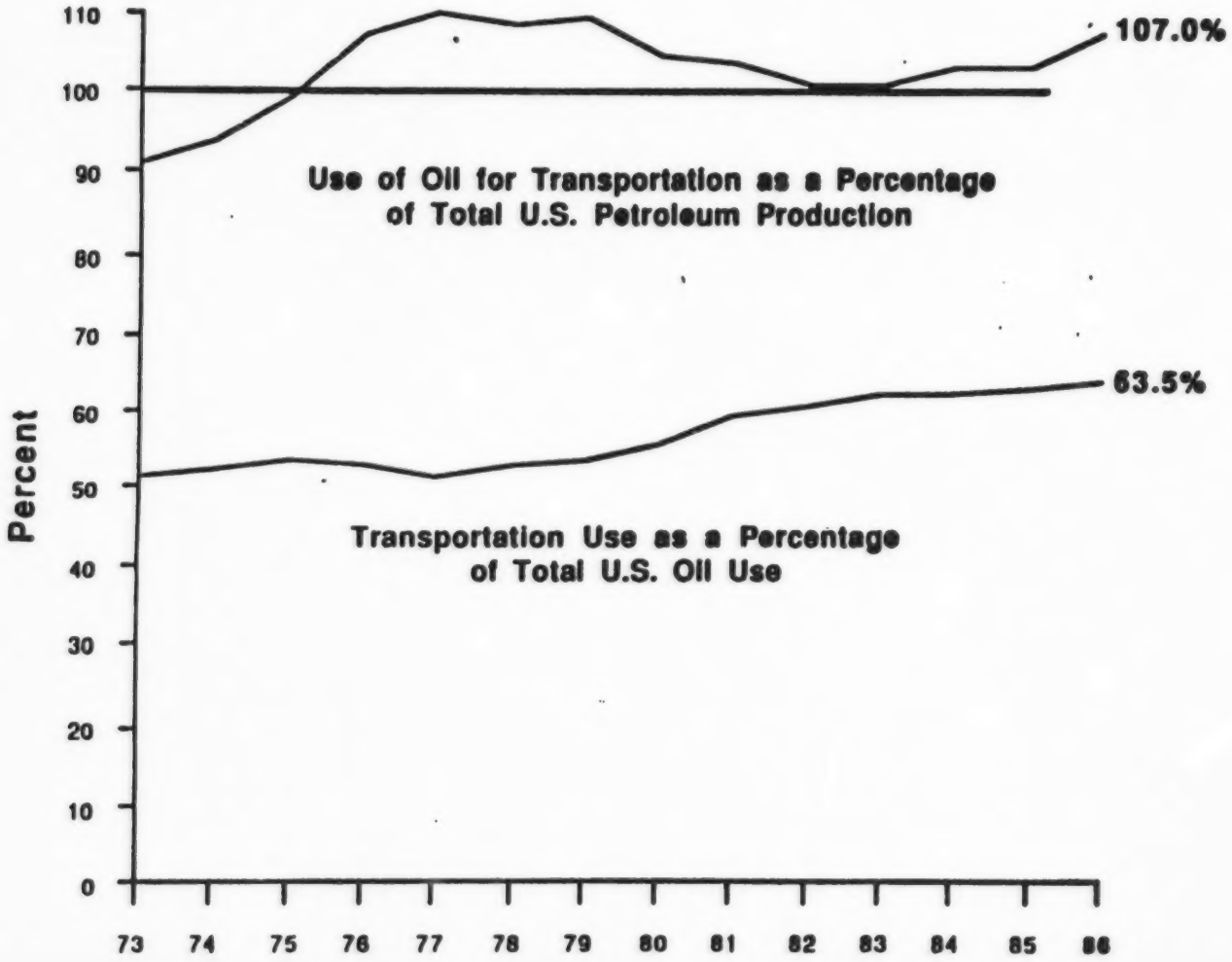
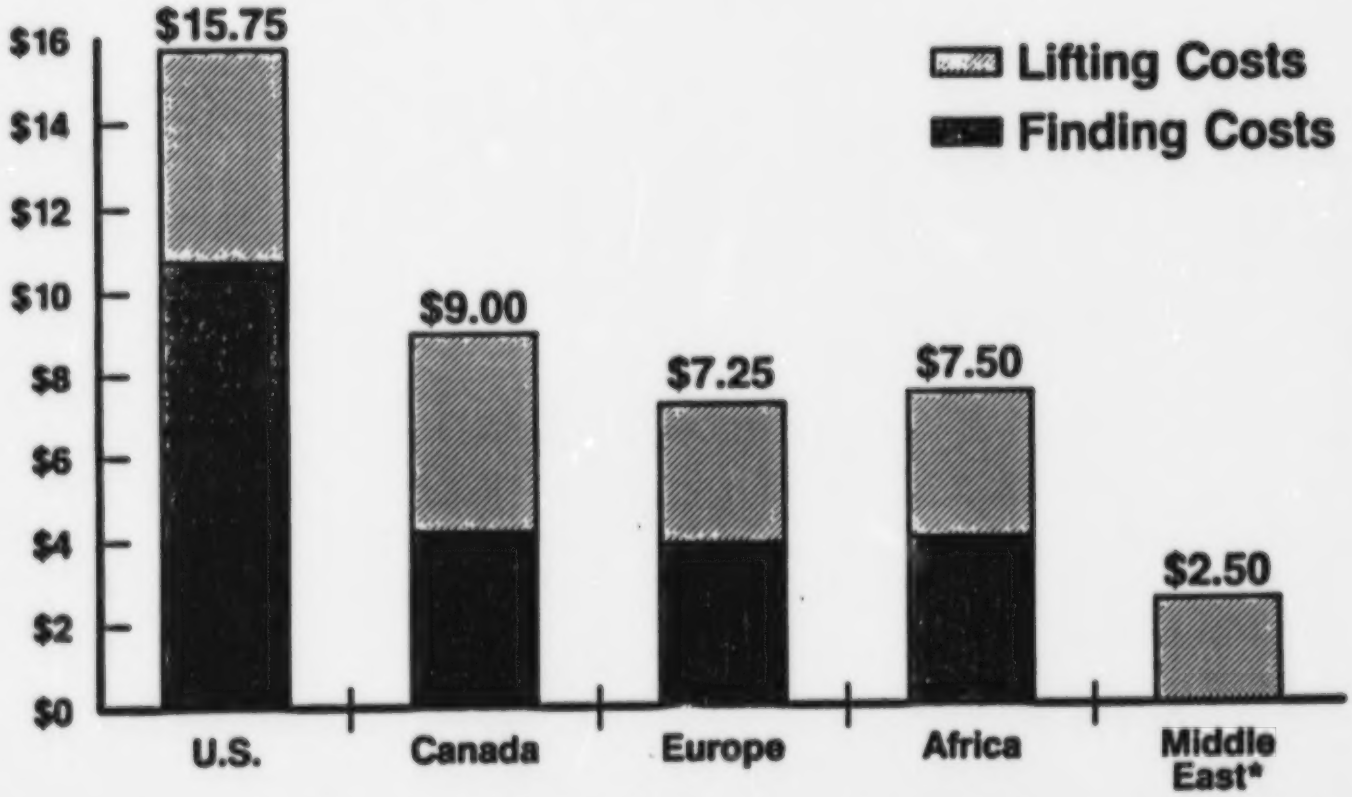
Transportation: This Sector Alone Uses More Oil Than the United States Produces



ENERGY POLICY ISSUES RELATE TO OTHER NATIONAL PRIORITIES

ENERGY POLICY ISSUES RELATE TO OTHER NATIONAL PRIORITIES

U.S. OIL PRODUCTION COSTS HIGHEST IN THE WORLD



* Middle East finding costs of $3.50 per barrel excluded because of 6 MMBD excess production capacity.

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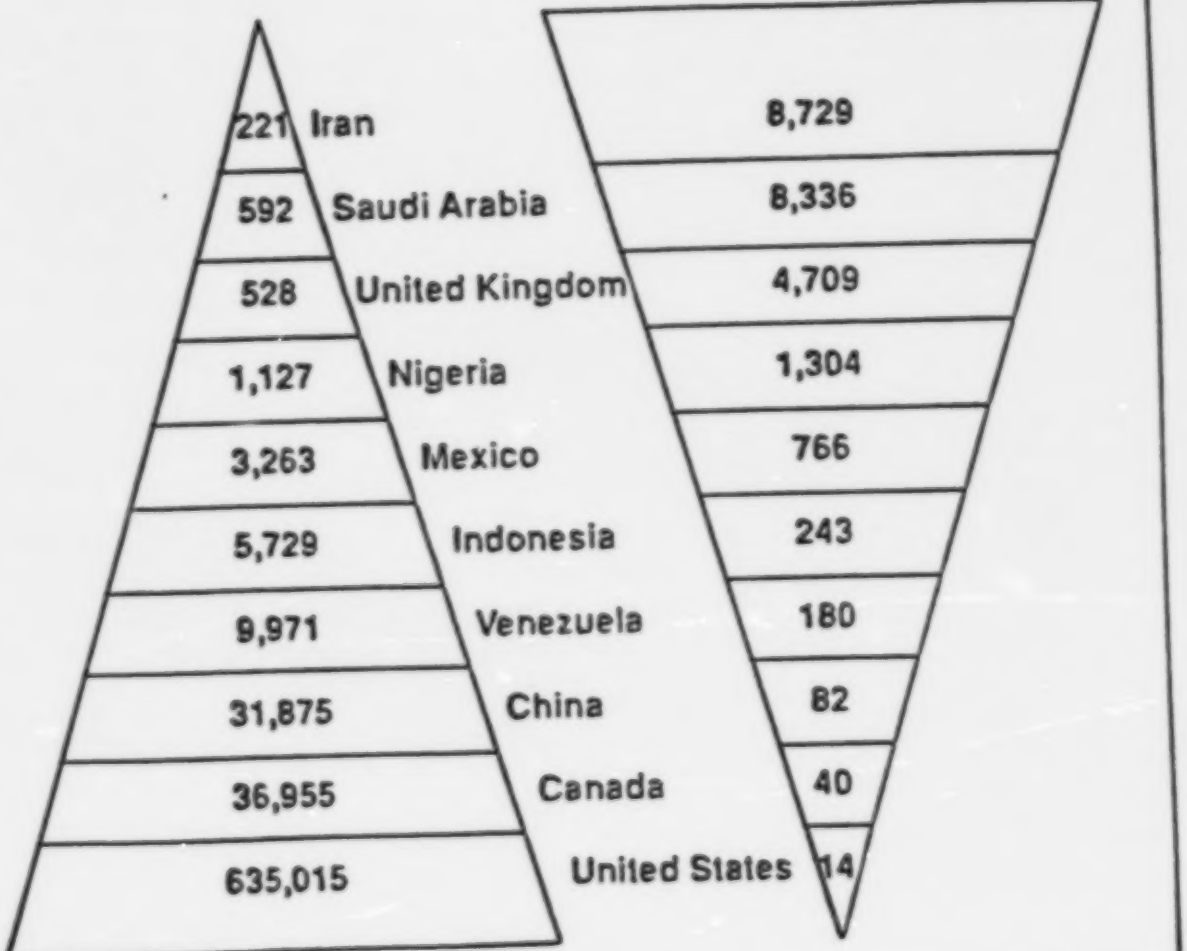
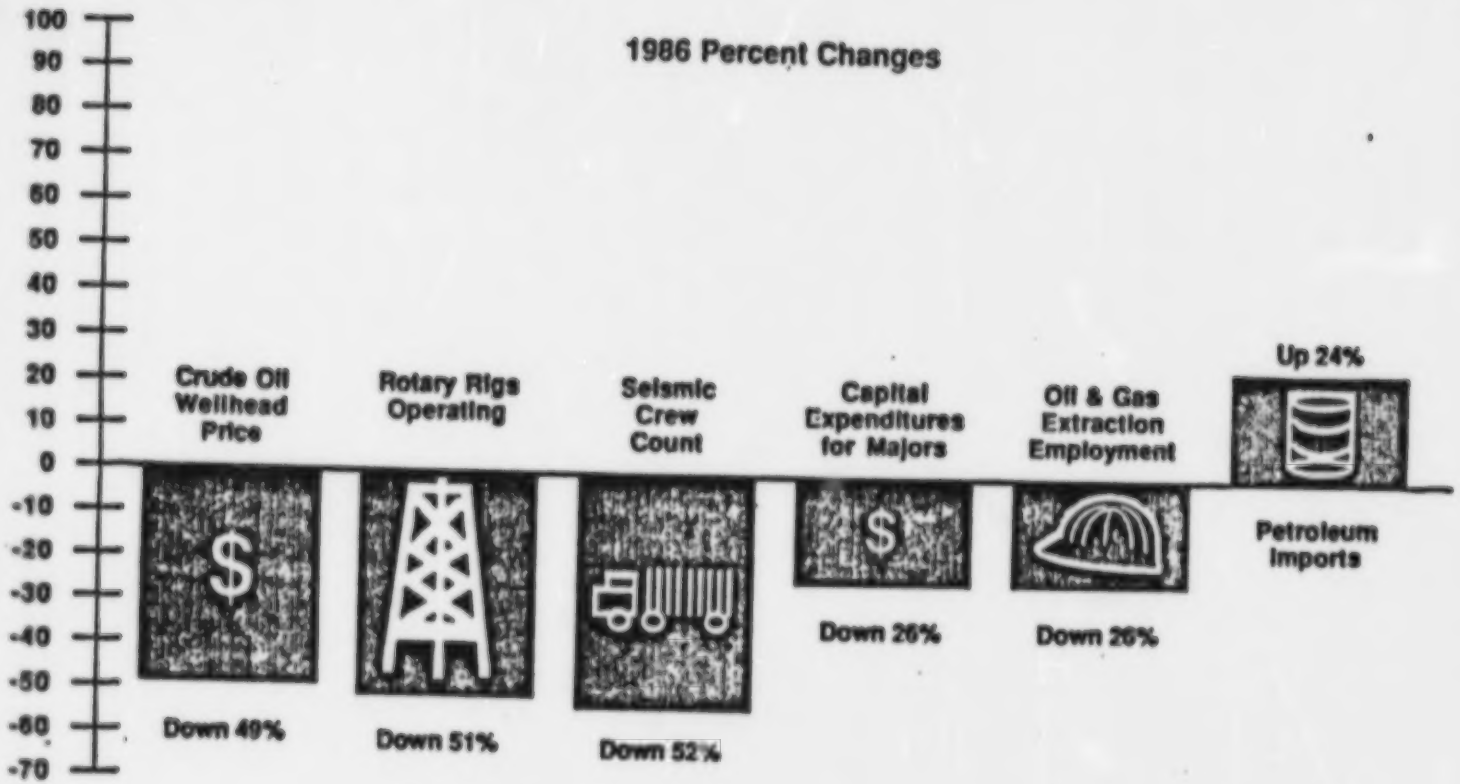
AVERAGE OIL WELL PRODUCING RATES



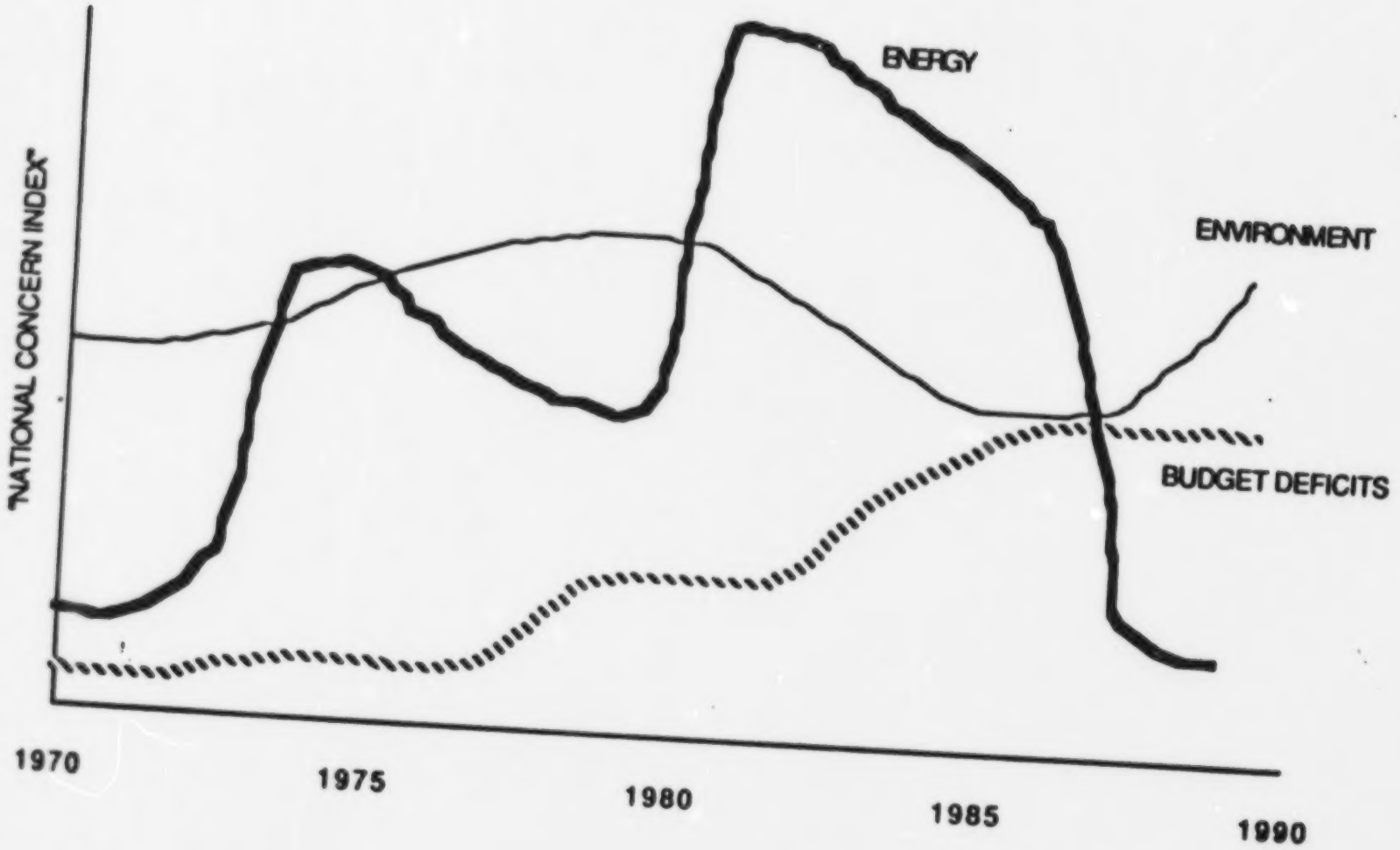
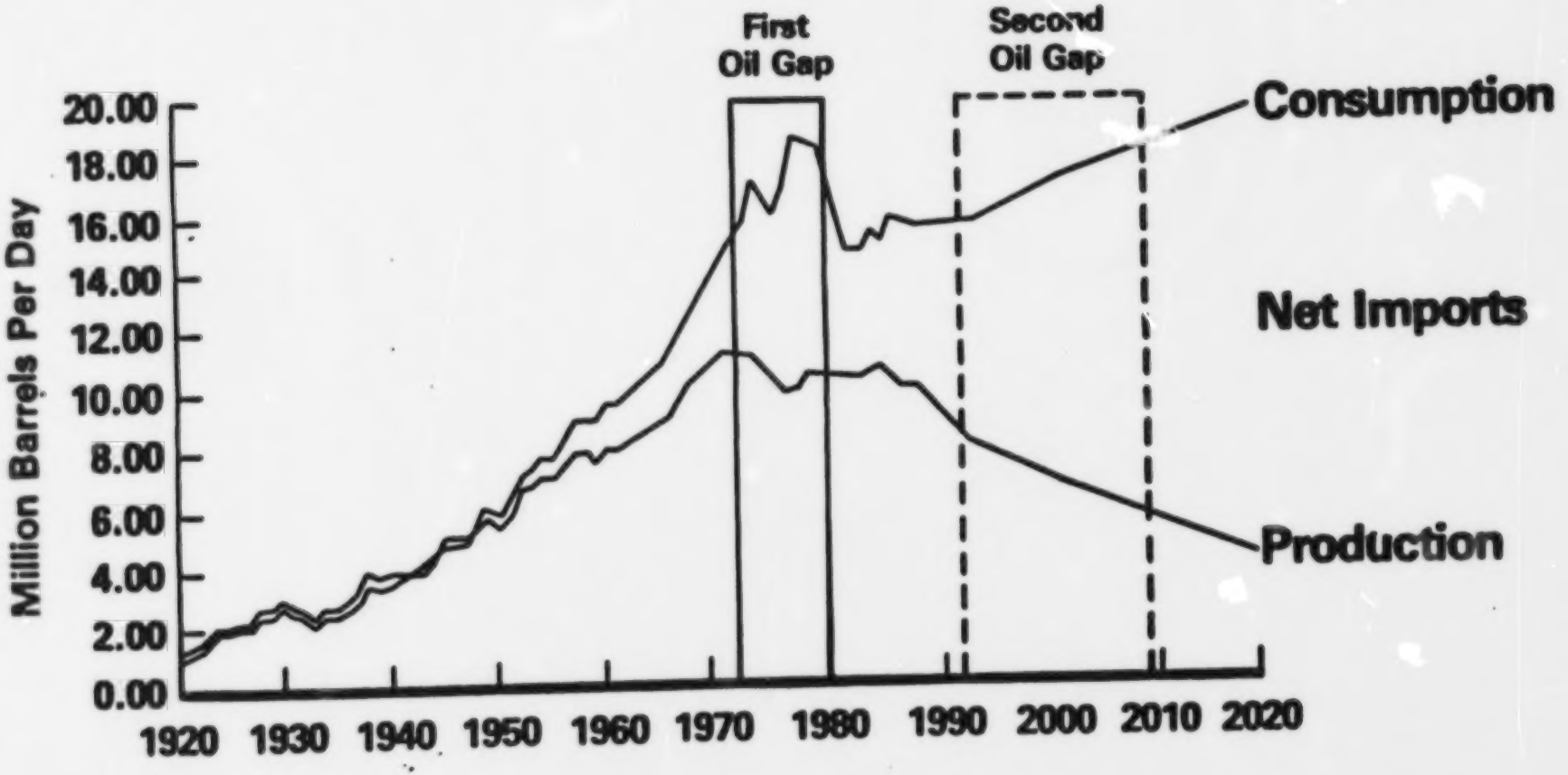
SOURCE: The Energy Report — April 4, 1988.



Source: Visual Concept, IPAA; Numbers, Department of Energy

ENERGY POLICY ISSUES RELATE TO OTHER NATIONAL PRIORITIES

NATIONAL CONCERNS CHANGE OVER TIME



THE UNITED STATES FACES ANOTHER OIL GAP BY THE END OF THIS CENTURY